GENERATION EXPANSION PLANNING OF NREB SYSTEM CONSIDERING CARBON EMISSION REDUCTION STRATEGIES

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CERTIFICATE

This is to certify that the work contained in this thesis entitled **"Generation Expansion Planning of NREB System Considering Carbon Emission Reduction Strategies"**, has been carried out by Priay ranjan Kumar (Y110446) under our supervision and that this work has not been submitted elsewhere for a degree.

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ABSTRACT

The electric energy is the key to the economic growth and improving the living standard of a country. In most of the Asian countries, particularly in India, there is shortage of enough generating plants to meet the required peak demand. Continuous addition of power plants requires the generation expansion to be carried out at regular intervals following a least cost approach. Increased awareness to both local and global environmental problem has forced the planners to include various mitigation criteria in the generation planning also. In the present thesis, an attempt has been made to include mitigation of green house gases (GHG), especially carbon dioxide, in the planning methodology.

In this work, the utility planning, cost & planning and environmental implications of supply- and demand-side options, imposition of carbon tax on fossil fuels proportionate to their carbon contents and ranking of barriers in adoption of clean and energy efficient (CEE) technologies have been studied. The study has been carried out for the Northern Regional Electricity Board (NREB) network of India utilizing 16^{th} Electric Power Survey data published by the Central Electricity Authority. Sensitivity analyses have also been carried out with respect to few important parameters associated with imposition of carbon tax and supply- and demand-side options to observe the trend in which the generation expansion planning shifts from its base case. In addition, the ranking of barriers in adoptions of CEE technologies has been carried out with the help of an Analytical Hierarchical process (AHP).

The study results reveal that the introduction of both supply- and demand-side options and imposition of carbon tax results in reduction of not only global pollutants such as carbon dioxide but also local pollutants such as NOx and SOx gases. The key barrier to the adoption of clean generation technology like IGCC and PFBC are the non availability of indigenous knowledge, their proven ness in Indian condition and lack of financial instruments, and those for solar based power plants are the high capital cost and lower efficiency.

CHAPTER 1

INTRODUCTION

1.1 GENERAL INTRODUCTION

Excessive green house gas emission is a global problem calling for international coordinated actions. Carbon dioxide (CO_2) is one of the Green House Gases (GHG) emitted from power sector, causing global warming. Therefore, to strive for specific target of CO_2 emission, one should start for a global target of CO_2 emission and create incentive to reduce CO_2 emission countrywide and sector wide in a cost-effective way. The link between changes in level of GHG and climate changes is firmly established. Methane, sulphur hexafluoride, chlorofluoro carbons, hydrofluoro corbons, perfluoro carbons and nitrous oxide are the other green house gases [19]. Carban dioxide is the most important green house gas contributing to the global warming. This and other green house gas traps the heat radiation and increases the temperature of atmosphere. Before the 20th century, it was found that the earth was cooling by about 0.02 degree Kelvin each century, but in just one century it has now warmed by nearly a degree Kelvin . The polar ice caps will melt due to the rise in temperature of atmosphere and the rise in sea level will cause the submergence of low level lands throughout the world.

It has been found that power sector is the major contributor to CO_2 emissions. In 1995, the share of power sector in total CO_2 emissions was estimated to be 45% in India [33]. The high rate of carbon dioxide emissions is due to the larger share of thermal power generation in the total electricity production. The share of thermal power generation are also likely to increase further with the expected growth of the electricity generation. For example, the share of thermal electricity generation is expected to increase from 78% in 2000 to 81% in 2010 in the case of India [33]. Consequently, it is expected that CO_2 emissions will increase considerably. There are number of technical options for reducing GHG and other harmful emissions from the power sector, which can be categorised as supply side options and demand side options. The traditional approach for electricity planning adopted by almost all electric utilities in the region is focused on expanding power supply capacity to meet the

growing demand, ignoring the GHG mitigation options. However, for an efficient allocation of resources in the power sector from the social perspective and environmental point of view, it is desirable to consider both the supply and the demand side options simultaneously in the electricity planning process. This relatively new approach is known as "Integrated Resource Planning" and is yet to be adopted in most countries in the region.

Fossil fuels fired power plants also emit local pollutants other than carbon dioxide, which are very hazardous to the human health. These are sulfur dioxide (SO_2), nitrogen oxides (NOx), carbon monoxide (CO), volatile organic compounds (VOCs), particulate matter less than 10 microns in diameter (PM10) and lead (in a very small amount) [30]. The major effects of these emissions are acid rain and increasing concentration of ozone in atmosphere [15].

Acid rain is caused by contamination of rain, fog or mist with sulfur dioxide and nitrogen oxides present in the air. These gradually react with water vapor in the clouds and become acids and reach the earth through rainwater. Undissolved acids may also fall on Earth by themselves or in combination with dust particles. These can acidify the surface waters and soil. This acidification of the water harms the aquatic life in lakes and rivers. In general, acid deposition, among other stressors, threatens the long-term structure, function, and productivity of many sensitive ecosystems.

Nitrogen oxides, emitted from power plants (along with VOCs) react in atmosphere in the presence of sunlight to form ozone. Strong concentrations of ozone can result in respiratory problems, irritation of eyes and mucous membranes. High levels of ozone can be harmful to vegetation also. Fossil-fuel power plants also produce a large amount of waste heat. Generally two-third of the heat value of the fuel pollutes the atmosphere thermally.

Carbon tax has attracted attention and commonly recognized as an economic instrument to achieve GHG emission mitigation. Also, GHG mitigation potentials of such policy measures are yet to be assessed in the case of most of the Asian countries. Also, imposition of tax lead to a cost-effective allocation of CO_2 emissions. The taxes, in allocation to reducing GHG emissions, are the additional revenue generation.

The environmental fiscal instruments such as carbon tax has some advantages over other taxes. First, the tax indicate the cost of good environment, second, they provide an incentive to introduce new technological processes promoting efficient and energy conservation, third they allow producers to choose where pollution abetment has to be implemented, thus contribute to reducing environmental damage at minimum economic cost and finally, taxes provide revenue that could be used to subsidize environmental technological innovation. Thus the benefit of the pollution tax may be somewhat different than expected in ideal economy, which has no distortion except for the external costs of pollution to be corrected by the pollution tax.

1.2 STATE-OF-THE-ART

The emission of Green House Gases (GHG) and global warming associated with it has made environmental issues to be much discussed in the recent literature. The power sector has been reported to be one of the main contributors of carbon dioxide emissions in many countries in Asia. As of 1999, the share of power sector in total carbon dioxide emission was estimated to be 45.6% in India; 41.9% in China and 33.6% in Thailand [3].

Electricity generation in Asia as a whole is expected to increase at a higher rate than the global average. The share of thermal power generation is also likely to increase given the expected growth of the electricity generation in this region. The shares of thermal electricity generation are expected to increase from 72% in 2002 to 81% in 2010 in case of India [9]. As on 18th Dec. 2002, out of total capacity of 103288.4 MW produced in India, 74375.2 MW is produced by thermal power plants [11]. Coal-based power plants share the major part of the power produced in India as it has large reserves of coal.

The coal-fired plants are a major source of greenhouse gases (GHGs) emission. According to a World Bank report, CO_2 emission in India by the year 2015 will be 775 million metric tons per year, as compared with 1000 million metric tons per year now produced by the entire European union. It also expects that SO_2 and NO_X production will be at three times the current levels [38]. From a global perspective, India will account for 18% of the increase in carbon emissions produced from energy use in developing countries

between 1985 and 2025 [34]. Hence, it has become mandatory to explore all the options while bringing the emission of pollutants within a target set.

In actual situation, some study such as the engineering contactor Bechtel in UK estimated the total cost, including CO_2 capture in the power plant and its disposal in ocean, would be US$ 30-180 per ton of avoided CO_2 emission. While in US study ranges from US$ 18 to 37 per ton of CO_2 capture in various type of power plant and the CO_2 disposal cost were estimated to be 15-50 US$ per ton of CO_2 disposed. These studies concluded that CO_2 capture and disposal techniques, although technically feasible, are still too expensive to be used as a CO_2 mitigation option [14].

Though the imposition of carbon tax is considered desirable by the developing countries in the long run, no proper study has been carried out regarding their environmental implications especially in the Asian countries (India). With the introduction of carbon tax, a utility would avoid generation and hence associated environmental emissions [12, 22, 26,].

The carbon tax is a duty levied on fossil fuels proportionate to their carbon content. The purpose is to move towards the internalization of the costs associated with the emission of CO_2 from the combustion of fossils fuels. Therefore, imposing carbon tax would increase the fuel cost [2]. Thus electricity industry would face higher prices for coal, gas and fuel oil and chooses to burn different fuels according to their relative prices. Also, the increase in fuel cost would affect the utility in their system cost, generation and capacity mix. Levy of carbon tax not only affect the electricity generation on supply side but also reduces the demand for electricity through the increase of electricity price due to tax. Furthermore, carbon tax could affect CO_2 emission through both supply- and demand side responses [2].

Carbon tax is efficient in static sense, in that they can reduce pollution at least cost; and in a dynamic sense, in that they steer technological change into a direction of greater ecological efficiency. Introduction of carbon tax would make the EETs and CTs cost effective. The total economy wide changes in GHG emission due to adoption of EETs and CTs with carbon tax in power sector is a combined effect of a number of factors. Four major factors that affect the total change in emissions; (i) final demand effect (i.e., the change in

emissions associated with changes in final demand), (ii) fuel mix effect (i.e., the change in emissions due to variation in fuel mix), (iii) structural effect (i.e., the change in emissions due to changes in technological coefficients with and without DSM) and (iv) Joint effect (i.e., the interactive effects between or among the final demand-, fuel mix- and structural-effects)[20].

The generation expansion planning considering clean and energy efficient (CEE) technologies to mitigate pollutant emission level select these plants in the system. However, these are not implemented in the system due to several types of barriers. Hence identification and ranking of barriers in adoption of these technologies is an important step [4]. The AHP (Analytic Hierarchical Process) model [12] is suitable tool for this because AHP combined deductive approach and systems approach of solving problems into one, integrated framework. The principles of guidance in AHP are decomposition, comparative judgment and synthesis of priorities. This method is simple, practical, systematic and effective. The hierarchy system can be formulated with objectives (termed as the focus), criteria and the different options (the barriers).

1.3 MOTIVATION BEHIND THE STUDY

Emission of greenhouse gases and other pollutants from the power sector and its firmly established link with global warming and environmental pollution has made this issue to be much discussed in the recent past. It has become a major concern all over the world to put a cap on the emissions from the power sector. Many of the developed countries have agreed to the Kyoto protocol and started an attempt to curb the greenhouse gas emissions. The United States signed the Framework Convention on Climate Change (FCCC) during the 1992, United Nations Conference on Environment and Development. Emission in developing countries is also increasing rapidly as the power sector is expanding at a much faster rate to meet their economic growth and with having large reserves of fossil fuels. Hence, it has become a moral responsibility for developing countries also to take some fast action for abatement of greenhouse gases. Also there is a lot of pressure from the developed countries on developing countries to curb their greenhouse gas emissions.

India has large reserves of coal and it accounts for almost 70% of the electricity generation in the country. However, the excessive use of coal produces large amount of carbon dioxide due to their high carbon content and incomplete combustion and contributes towards the global warming. The total contribution of India in carbon emissions is estimated to be 45.6% in Asia. So it has become the need of the moment to shift our electricity generation from conventional fuels to renewable energy supplies as much as possible and shake hands with the rest of the world in making it pollution free.

Since carbon tax imposition on fossil fuels proportionate to their carbon content which are used as fuels in power generations and power generation by clean and energy efficient (CEE) technologies are going to play a very important role in the near future in the power generation sector, it has become imperative to know their environmental implications in the long-run. A large number of studies have shown that a significant proportion of clean and energy-efficient (CEE) technologies that have significant impact on Indian energy use and GHG emissions, are cost effective and not adopted. In that context, it is important to study whether there are other characteristics, other than cost that are more important in adopting CEE technologies in power sector. The main purpose of this work is to exploit, what are the other important characteristics (other than cost) in adopting CEE technologies or to identify the major barriers to the adoption of these technologies and rank them. The main objectives of this study has been the following:

1. To find out the impact of supply- and demand-side options for generation expansion planning including utility, cost and environmental implications.
2. To find out the utility implication, cost implication and environmental implication of carbon tax including their effect on the reliability of the system.
3. To identify and rank the barriers to adoption of CEE technologies in power sector.

1.4 THESIS ORGANIZATION

This thesis has been organized in five chapters.

The present **Chapter 1** gives a brief outline of the generation expansion planning, discusses importance of GHG mitigation and set the mitigation behind, presents a brief state-of-the-art to the work carried out in this thesis.

Chapter 2 presents the results of the generation expansion planning considering both TRP & IRP models with certain level of CO_2 mitigation target. It provides the cost, utility & environmental implications of supply- and demand-side options for mitigating environmental emissions. In supply side options PFBC, IGCC and BIGCC are taken as clean technologies and wind and solar plants are taken as renewable technologies. Three demand side options are considered. Utility planning implications, cost and pricing implications and environmental implications of both TRP and IRP case are considered.

Chapter 3 provides the generation expansion planning results analyses, the cost and environmental implications of imposition of carbon tax on fossil fuels. The study has been carried out for Northern Regional Electricity Board system of India.

Chapter 4 presents an AHP based model for the ranking of barriers in adoption of CEE technologies. The key barriers for four of the CEE technologies (IGCC, PFBC, BIGCC and Solar) have been identified.

Chapter 5 concludes the main findings of the work reported in this thesis and identifies few areas of further research.

CHAPTER 2

LEAST COST GENERATION EXPANSION PLANNING WITH EFFICIENT TECHNOLOGIES

2.1 INTRODUCTION

The aim of the energy resource planning is to investigate comprehensively the effective use, co-ordination and substitution relationship of various primary resources, such as coal, crude oil, natural gas, hydro energy, nuclear energy etc. The least cost generation expansion planning is to seek the most economical generation expansion scheme achieving a certain reliability level according to the forecast of demand increase in a given period of time. The cost factor includes the capital investment cost and the power generating cost. Capital investment cost denotes the total capital outlay necessary to build a power plant. Power generation cost represents the total cost of generating electricity. It includes the fuel cost, fixed operating and maintenance cost and variable operating and maintenance cost. Fuel costs play a major role in the least cost generation planning. Different types of fuels, considered in this study are coal, gas, oil and nuclear. The coal is further categorized into six types according to their calorific value, cost and different process required for the combustion of fuel.

This study is aimed at providing valuable insight on the cost-effective technologies available for GHG (only CO_2) mitigation, which need to be adopted in the power generation expansion plan. GHG emission is used as an additional constraint in generation expansion planning. Role of supply side and demand side options has been analyzed towards the contribution of GHG and other harmful gases (NO_x and SO_2) taking the input data for the Northern Regional Electricity Board (NREB), India. In supply side options, Pressurized and Fluidized Bed Combustion (PFBC) and Integrated Gasification Combined Cycle (IGCC) are taken as clean coal technologies and wind & solar plants are taken as renewable technologies. Three types of demand side options are considered. Study covers utility planning implications, cost and pricing implications, and environmental implications of TRP

and IRP cases. Study is limited to a planning horizon of 15 years viz. from year 2003 to 2017. Integrated Resource Planning Analyses (IRPA) package developed by AIT and CPLEX [16] software has been used for getting the least cost optimal generation expansion plan.

2.2 MATHEMATICAL FORMULATION

The formulation of the conventional generation expansion planning is based on the least cost optimization criteria [7]. The least cost generation expansion planning minimizes the total cost of candidate power plants and the cost of power generation from existing and candidate power plants over the complete planning horizon. Let, the total planning horizon is for T years, each year having 's' seasons, each season divided into 'P' blocks, each block divided into 't' vintages, J being the total number of candidate power plants and K being the total number of existing power plants.

Mathematically, the least cost generation expansion plan has objective to,

$$\text{Minimize } \sum_{j=1}^{J}\sum_{v=1}^{T}\left(C_{jv}-W_{jv}\right)\times Y_{jv}+$$

$$\sum_{t=1}^{T}\sum_{s=1}^{S}\sum_{p=1}^{P}\sum_{v=1}^{t}\sum_{j=1}^{J}U_{jpstv}\times F_{jpstv}\times N_{st}\times\theta_{pst}+$$

$$\sum_{t=1}^{T}\sum_{s=1}^{S}\sum_{p=1}^{P}\sum_{v=-V}^{t}\sum_{k=1}^{K}U_{kpstv}\times F_{kpstv}\times N_{st}\times\theta_{pst} \qquad (2.1).$$

where,

C_{jv}: Discounted capital cost of candidate power plant j, to be commissioned in vintage v.

W_{jv}: Discounted salvage value of power plant j, commissioned in year v after time horizon T.

Y_{jv}: Number of power plants of type j installed in year v (An integer variable).

YP_{mv}: Number of pump storage hydro plants type m installed in year v (An integer variable).

N_{st}: Number of days in season s of year t.

θ_{pst}: Width of block p of chronological load curve of season s of year t.

U_{jpstv}: Power generation from candidate plant j of vintage v in block p of season s in

year t.

F_{jpstv}: Cost of per unit power generation from candidate power plant j of vintage v in block p of season s in year t.

U_{kpstv}: Power generation from plant k of vintage v in block p of season s in year t.

F_{kpstv}: Cost of per unit power generation from existing or committed power plant k of vintage v in block p of season s in year t.

The above optimization process is subjected to following constraints

- Demand constraints
- Reliability constraints
- Guarantee condition for energy supply for mixed hydro thermal system
- Plant availability constraints
- Annual energy constraints
- Hydro energy availability constraints
- Maximum potential capacity constraints
- Fuel or resource availability constraints
- Calculation of emission constraints and heat rate

The mathematical description of these constraints is given in Appendix-A

The CO_2 mitigation strategies have been incorporated in the form of imposing limit values to total CO_2 emission. If the total CO_2 emission in year-n without emission constraints has been $(ECO_2)_{0,n}$ and if a reduction target of X % has been imposed on the total CO_2 emission.

Then the constraint of CO_2 emission for year n can be written as

$$(ECO_2)_{1,n} \leq \left(1-\frac{X}{100}\right) \times (ECO_2)_{0,n}$$

The value of X in the present study has been taken as 5,10 and 15%.

2.3 INPUT DATA AND ASSUMPTIONS

Indian electricity sector consists of five Regional Electricity Boards (REBs) further divided into State Electricity Boards (SEBs). These REBs exist to promote the integrated operation between SEBs in that region. The five REBs are listed as

1. Northern Regional electricity Board (NREB) having HQs at New Delhi
2. Southern Regional electricity Board (SREB) having HQs at Bangalore

3. Western Regional electricity Board (WREB) having HQs at Mumbai

4. Eastern Regional electricity Board (EREB) having HQs at Kolkata

5. North-Eastern Regional electricity Board (NEREB) having HQs at Shillong

The present study has been carried out for the Northern Regional Electricity Board (NREB) system.

2.3.1 Overview of the Northern Regional Electricity board (NREB) system, India

India has seen a significant progress in the electric sector since independence. The installed generating capacity has increased sixty-one fold and annual electricity generation by ninety-three folds between 1947 and 2002. But still, there exists a wide gap between demand and supply. For NREB system, consisting of eight states namely Rajasthan, Punjab, Delhi, Haryana, Himachal Pradesh, Uttar Pradesh, Uttaranchal and Jammu & Kashmir, peak demand is 26.94% .

During 11th plan i.e. 2002-2007; generating capacity addition of 66654 MW at central level and 15427 MW in NREB has been completed. Installed generating capacity at the end of 10th plan was 103288.4 MW for India and 28071.5 MW for NREB. The installed capacity of NREB as on Dec2002 was 28071.5 MW in total. At the end of 11th plan, private sector share in total installed capacity of India was 28491 MW. There are 160 thermal power plant units and 230 hydro power plant units in NREB. They are given in Appendix C. Installed capacity of different types of plants is shown in Table 2.1 for the NREB system [11].

Table 2.1: Present installed capacity in NREB dated 18/12/02
Source Central Electricity Authority (CEA)

Plant Type	Monitored Capacity (MW)	Generation (MW)
Thermal	18265.7	15082.0
Hydro	8575.8	4299.0
Nuclear	1230.0	1127.0
Total	28071.5	20508.0

The Hydrothermal mix at present in NREB is around 32:68 and there is large hydro potential available in the NREB.

At present in India, CEA has been using two computer software models for power generation expansion planning, namely:

1. Electric Generation Expansion Analysis System (EGEAS)
2. Integrated System Planning Model (ISPLAN)

The EGEAS model, being a probabilistic model, provides for long range generation expansion planning as it yields very useful quantitative measures of reliability of power supply in the future years and gives the total cost of operating the existing and committed system and installing and operating the new systems. The transportation of fuel and transmission of power are not considered in the EGEAS model and considered in ISPLAN. The sitting of new generating stations, that use transportable fuel, is done using ISPLAN. Under ISPLAN the broad features of the transmission system are also obtained. The EGEAS model is probabilistic model, whereas ISPLAN is deterministic model. CEA utilizes the power reliability indices as Loss of Load Probability (LOLP) of 2% and Energy not Served (ENS) not to exceed 0.15% [CEA1].

2.3.2 Transmission and distribution scenario

The principal transmission voltages in the NREB are 400 kV, 220 kV and 132 kV. At the end of 1995 – 1996, the lines in operation were 34279 km. of 400 kV, and 76930 km. of 220 kV in the country. A large network of transmission lines exists at lower voltage also. Apart from Extra High Voltage (EHV) alternating current transmission lines, high voltage direct current lines are also there and the first being the ± 500 kV Rihand – Dadri line over a distance of 817 km.The transmission and distribution loss in the country is at about 24.79% in 1997-1998 [31]. This level of transmission and distribution losses is considered to be very high and efforts are being made to reduce the losses.

2.3.3 Electricity Demand Data

In the beginning of 11^{th} plan (in the end of 2002) the peak demand in NREB was 28071.5 MW. Electricity demand forecasting for NREB system has been taken from 16^{th} Electric Power Survey (EPS) of India [31]. As per the projection, forecast for NREB system is shown in table 2.1. In IRPA, demand forecast was required to be projected up to the year 2017, for which the forecast data is not available. So, peak demand up to 2017 has been

extrapolated by taking average percentage growth of 6.42%. Demand in between the years i.e. between 2001-02 & 2006-07, 2006-07 & 2011-12, have been calculated through interpolation of EPS data. Detailed forecast for each year of planning horizon is shown in Table 2.2

Table 2.2: Electricity demand data [31]

Year	Peak Load (MW)
2003	33800
2004	36169
2005	38613
2006	41223
2007	44009
2008	46835
2009	49843
2010	53044
2011	56451
2012	60077
2013	63935
2014	68040
2015	72405
2016	77055
2017	82000

2.3.4 Other Assumptions Used in the Analyses

In the present study, most of the data are actual or according to the norms used in India for power generation expansion planning and very few assumptions are made. These assumptions are listed below.

1. Twenty blocks are taken in one season and two seasons are considered in one year. Season 1 is of total 92 days (July, August and September) and season 2 (rest of the months) consisting of total 273 days.
2. Operating cost is taken as 1% of the total capital cost and fixed operating and maintenance (O&M) cost as 2.5% for thermal plants. Operating cost for hydro plants is assumed to be zero and fixed O&M cost is taken as 1.5% of the total capital cost.

3. In DSM data, replacement of incandescent bulbs by Compact Fluorescent Lamps (CFL) is derived from the available references [10][17] [25] [36] [37]. Breakdown of GLS lamps of different power ratings i.e. 40, 60, 100 watts and others in residential sector are assumed in the ratio of 45:35:15:5. Breakdown of installed GLS lamps in different sectors i.e. domestic, commercial and industrial are assumed in the ratio of 70:25:5.

2.3.5 Supply Side Options

2.3.5.1 Clean-coal technologies

The two types of clean technologies viz. Pressurized Fluidized Bed Combustion (PFBC) and Integrated Gasification Combined Cycle (IGCC) are considered as supply side options in the present study, which are briefly discussed below.

- **Pressurized fluidized bed combustion**

By using Pressurized Fluidized Bed Combustion (PFBC) technology, the plant efficiency can be improved up to about 45%. PFBC is clean coal technology associated with coal gasification. Main furnace operates under pressure. In this technology, ash, sulphur and impurities are removed at the combustion stage of the fuel to be burnt to control different emissions. The lime is added in the coal at the time of combustion of coal, so that the energy required for burning the sulphur, could be saved. The lime reacts with the sulphur forms the compound and comes out as waste matter. The SO_2 emission will be less in this case. NO_x is controlled by lowering temperature of combustion, water spray or using special burner. Fluidized bed combustion can burn coal efficiently at a temperature low enough to that of the powder coal burning temperature. As the NO_x emission depends on the combustion temperature, its level will decrease. Due to the gasification of the coal, the CO_2 emission will also be less.

- **Integrated gasification combined cycle**

Integrated Gasification Combined Cycle (IGCC) is a promising power generation option, which can be applied to a great variety of solid or liquid feedstock. It offers some unique options such as co-production of electric power, bricks and chemicals simultaneously. It is the technology employed to control emission at the combustion stage of the fuel. By using this, one can reduce pollutant's emission level and water consumption amount besides improving the overall efficiency of the power plants, which may be more than 45%. In such

plants, the coal is gasified to lower degree before it goes to the combustion. Before going to combustion and at the time of gasification the lime is added to the coal to take out sulphur before burning of the gasified coal. Reduction in sulphur compound can be achieved by clean up at 350-400 °C by absorption on supported iron oxides. Coal gasification provides a potential option for reducing CO_2 emission of coal-fired plants. As the burning temperature is low enough, so the NO_x emission is low. The high ash (30%-40%) content of Indian coal requires IGCC technology for the power generation.

2.3.5.2 Renewable technologies

In the present study, wind and solar power plants are considered as renewable technologies. Wind power plant generation has got large momentum in India and at present, it is having 1024 MW of wind power generation and 32 MW generations from solar photovoltaic. A 165 MW power plant based on photovoltaic generation has been proposed at Maithania, Rajasthan. In wind power generation, India is among the one of the four top countries. Most of the wind power plants in India (95%) are handled by private organization [21].

Renewable technologies are useful for rural electrification, as in India there are still 14% villages that have to be electrified [7]. In the present study, 2 MW units of wind and solar plants are considered as supply side options.

2.3.5.3 DSM options

Five types of demand side options are considered for the present study, three in the residential sector and two in the agricultural sector. These are listed in Table 2.3.

Table 2.3: DSM options

Sector	*DSM options*
Residential	DSM 1: Replacement of 100 W incandescent bulb by 20W CFL DSM 2: Replacement of 60W incandescent bulb by 11W CFL DSM 3: Replacement of 40W incandescent bulb by 9W CFL
Agriculture	DSM 4: Replacing inefficient pumps by efficient one DSM 5: Partial rectification of pumps

End use efficiency improvement and Demand Side Management (DSM), offer new hope to Indian utilities to bring the demand and supply of electricity closer into balance, when the country is experiencing an overall energy deficiency with peak demand remaining unserved.

In 1991-1992, the domestic sector consumed 17% of the total electricity sales in the country. Both the number of consumers and per capita consumption of electricity in the domestic sector are growing at fast rate, and the share of the Domestic sector in total electricity consumption is estimated to increase to 36.6% by 2006-2007. Lighting account 28% share of total domestic energy consumption. Present lighting use in the domestic sector is largely from incandescent lamps and to some extent from fluorescent lamps. In the domestic sector, there exist a very strong case for substituting low efficiency incandescent lamps with high efficiency fluorescent lamps, while maintaining or increasing the level of lumen output [37]. In 1998, number of GLS lamps in northern region was 79.24 million [37]. Thus, there exist a large potential to save energy by replacing GLS with CFL. In the present study, DSM data for the residential sector are derived from different available literature. Chronological load curve of the residential sector is based on survey report done for Gujarat State Electricity Board (GSEB) [36].

2.3.6 Description of Cases

A total of eight cases have been considered in the present study.

2.3.6.1 Traditional resource planning (TRP) base case

For TRP base case analyses, data are the same as the input data used for the generation expansion planning by CEA, New Delhi in the country. These data are prepared in IRPA format. Demand data are shown in Table 2.2.

Load factor is calculated by projected energy and projected peak demand. Reserve margin is taken as 5% for all the years, which is the norm followed by CEA for planning in India. Total ten types of fuels are taken naming coal 1, coal 2, coal 3, coal 4, coal 5, coal 6, gas, nuclear, lignite and oil. Costs for various types of fuels are shown in Annex C2. Cost multiplication factor for year 2003 is taken as 1.2 and for the rest of the year; it is taken as 1.05 referred to the base year 1998. Four types of plants are taken, namely the conventional coal, combined cycle gas turbine unit, nuclear and lignite type, which are sufficient to include all the plant types. Transmission loss rate is taken as 4% for all the plants. Minimum

operating capacity is taken as 30% of the installed capacity. Heat rate is taken from available plant monthly report.

Four types of candidate thermal power plants and twenty-one types of hydro power plants are considered. The four types of candidate thermal power plants are coal 4 - 500, coal 6 – 500, CCGT 250 and nuclear 500. Annual maintenance hours are taken as 864 for nuclear and coal based plant, 1296 for gas and oil based candidate plants. Availability for nuclear is taken as 0.58, for CCGT as 0.8 and for coal based plant as 0.71. For Hydro plants, it is taken as 0.9. These candidate power plants are listed in Appendix C.

2.3.6.2 Traditional resource planning with efficient/clean supply side options with 5% annual emission reduction target (TRP1 case)

In the TRP1 case, four additional efficient/clean candidate power plants namely IGCC, PFBC, wind and solar are considered. Detailed data for these are shown in Annex C1. An additional constraint on annual CO_2 emission was added in this case. IRPA model was enforced to reduce CO_2 annual emission by 5% of TRP case. All other datas are taken same as in the TRP case. Annual expected CO_2 emissions limits (5% reduction of CO_2 emission of TRP case).

2.3.6.3 Traditional resource planning with efficient/clean supply side options with 10% annual emission reduction target (TRP2)

In TRP2 case, all the input data are same as in TRP1 case except the expected CO_2 annual emission limit. In this case, emission reduction target is taken as 10% of the CO_2 emission in the TRP case.

2.3.4.4 Traditional resource planning with efficient/clean supply side options with 15% annual emission reduction target (TRP3)

In TRP3 case, all the input data are same as in TRP1 case except the expected CO_2 annual emission limit. In this case, emission reduction target is taken as 15% of the CO_2 emission in the TRP case.

2.3.4.5 Integrated resource planning base case (IRP)

In IRP case, three DSM options, discussed in section 2.3, are taken as an additional input. All other input data is same as in the TRP case. DSM case flag in IRPA basic data form is set to 2 (restricted).

2.3.4.6 Integrated resource planning with efficient/clean supply side options with annual 5% emission reduction target (IRP1 case)

IRP1 input data are same as IRP input data except the additional CO_2 emission constraint. Expected annual CO_2 emission (5% reduction in CO_2 emission of TRP case) .

2.3.4.7 Integrated resource planning with efficient/clean supply side options with 10% annual emission reduction target (IRP2)

IRP2 input data are same as IRP input data except the additional CO_2 emission constraint with 10% reduction in CO_2 emission of TRP case.

2.3.4.8 Integrated resource planning with efficient/clean supply side options with 15% annual emission reduction target (IRP3)

IRP3 input data are same as IRP input data except the additional CO_2 emission constraint with 15% reduction in CO_2 emission of TRP case.

2.4 RESULTS AND DISCUSSIONS

2.4.1 Utility Planning Implications

2.4.1.1 Capacity-mix and generation-mix

Table 2.4 and Table 2.5 show the capacity mix and generation mix for all the considered plant types for cases TRP, TRP1, TRP2, TRP3 IRP, IRP1, and IRP2 and IRP3. It is observed from Table 2.4 that hydrothermal capacity mix is highest in 2007 and thereafter it has declining trend. Solar plants are not selected in any of the cases. Wind plants are selected in all the cases because for their low capital cost. For all the cases, capacity mix of coal type of plants is increasing for the unconstrained cases but for the constrained cases it is minimum in 2007. Capacity mix of CCGT plants is decreasing for all the cases. Hydrothermal mix in IRP cases are more than as compared to the TRP cases. Capacity mix of PFBC and IGCC plants are more for TRP cases as compared to IRP cases and they show a increasing trend

over the planning horizon. Generation mix for all the considered plant types exhibits similar trend as the capacity mix discussed above.

Table 2.4a: Capacity mix by plant types for TRP case

Generation Expansion Planning Case		Capacity mix (%)										Total Capacity (MW)
		Hydro	Coal	CCGT	Nuclear	Lignite	PFBC	IGCC	Wind	Solar	Biomass	
TRP	2003	27.4	31.5	38.1	2.4	0.5	0.0	0.0	0.1	0.0	0.0	44568.7
	2007	32.1	34.8	29.7	1.8	0.8	0.0	0.7	0.1	0.0	0.0	57885.7
	2012	29.2	40.0	22.1	1.4	0.6	5.2	1.5	0.1	0.0	0.0	77862.7
	2017	24.7	43.2	21.7	1.9	0.4	4.2	3.7	0.1	0.0	0.0	106770.7
TRP1	2003	27.4	31.5	38.1	2.4	0.5	0.0	0.0	0.1	0.0	0.0	44568.7
	2007	32.3	30.7	29.9	2.7	0.8	0.0	3.5	0.1	0.0	0.0	57485.7
	2012	29.0	39.7	21.9	3.3	0.6	1.1	4.1	0.1	0.0	0.2	78344.7
	2017	24.6	39.9	23.1	3.8	0.4	4.2	3.7	0.1	0.0	0.1	106902.7
TRP2	2003	27.4	31.5	38.1	2.4	0.5	0.0	0.0	0.1	0.0	0.0	44568.7
	2007	32.5	28.2	30.0	2.7	0.8	1.6	4.2	0.1	0.0	0.0	57285.7
	2012	29.2	32.4	23.4	3.3	0.6	5.8	5.2	0.1	0.0	0.0	77612.7
	2017	24.7	38.6	23.2	3.8	0.4	4.2	3.8	0.1	0.0	1.2	106590.7
TRP3	2003	26.8	30.8	39.4	2.3	0.5	0.0	0.0	0.1	0.0	0.0	45568.7
	2007	32.5	28.2	32.2	2.7	0.8	0.0	3.5	0.1	0.0	0.0	57235.7
	2012	29.4	28.0	28.1	3.3	0.6	5.2	5.2	0.1	0.0	0.0	77162.7
	2017	24.7	38.6	23.2	3.8	0.4	4.2	3.8	0.1	0.0	1.2	106590.7

Table 2.4b: Capacity mix by plant types for IRP cases

Generation Expansion Planning Case		Capacity mix (%)										Total Capacity (MW)
		Hydro	Coal	CCGT	Nuclear	Lignite	PFBC	IGCC	Wind	Solar	Biomass	
IRP	2003	27.7	31.9	37.4	2.4	0.5	0.0	0.0	0.1	0.0	0.0	44068.7
	2007	33.2	34.2	29.8	1.9	0.8	0.0	0.0	0.1	0.0	0.0	55985.7
	2012	30.6	42.0	24.5	1.4	0.6	0.6	0.0	0.1	0.0	0.0	74062.7
	2017	26.4	46.3	24.8	1.1	0.5	0.9	0.0	0.1	0.0	0.0	99670.7
	2003	27.7	31.9	37.4	2.4	0.5	0.0	0.0	0.1	0.0	0.0	44068.7
	2007	33.2	29.7	29.8	2.8	0.8	0.0	3.6	0.1	0.0	0.0	55985.7

	2012	30.4	39.9	22.8	3.5	0.6	0.0	2.7	0.1	0.0	0.0	74222.7
	2017	26.3	44.6	23.9	2.6	0.5	0.0	2.0	0.1	0.0	0.0	100020.7
IRP2	2003	27.7	31.9	37.4	2.4	0.5	0.0	0.0	0.1	0.0	0.0	44068.7
	2007	33.4	29.0	30.0	2.8	0.8	0.0	3.6	0.1	0.0	0.2	55617.7
	2012	30.8	34.1	26.4	3.5	0.6	0.0	4.3	0.1	0.0	0.2	73694.7
	2017	26.3	41.1	24.7	4.1	0.5	0.0	3.2	0.1	0.0	0.1	100102.7
IRP3	2003	27.6	31.7	37.7	2.4	0.5	0.0	0.0	0.1	0.0	0.0	44318.7
	2007	33.4	29.0	30.4	2.82	0.8	0.0	3.6	0.1	0.0	0.0	55735.7
	2012	31.4	23.7	30.0	2.9	0.6	6.2	5.0	0.1	0.0	0.2	72344.7
	2017	26.7	34.1	25.0	4.1	0.5	4.6	4.1	0.1	0.0	0.8	98562.0

Table 2.5a: Generation mix by plant types for TRP cases

Generation Expansion Planning Case		Generation mix (%)										Total Generation (GWh)
		Hydro	Coal	CCGT	Nuclear	Lignite	PFBC	IGCC	Wind	Solar	Biomass	
TRP	2003	24.5	37.6	34.7	2.5	0.6	0.0	0.0	0.1	0.0	0.0	196970.3
	2007	27.8	42.3	25.9	1.9	0.9	0.0	1.0	0.1	0.0	0.0	256455.3
	2012	25.5	48.6	13.7	1.4	0.7	7.8	2.3	0.1	0.0	0.0	350090.9
	2017	20.3	51.7	13.5	2.0	0.5	6.3	5.6	0.1	0.0	0.0	477853.8
TRP1	2003	24.5	32.9	39.4	2.5	0.6	0.0	0.0	0.1	0.0	0.0	196970.3
	2007	27.8	36.8	26.3	2.8	0.9	0.0	5.2	0.1	0.0	0.0	256455.3
	2012	25.5	48.4	14.0	3.3	0.7	1.7	6.1	0.1	0.0	0.1	350090.9
	2017	20.3	47.2	15.9	3.9	0.5	6.3	5.6	0.1	0.0	0.2	477853.8
TRP2	2003	24.5	27.4	45.2	2.5	0.3	0.0	0.0	0.1	0.0	0.0	196970.3
	2007	27.8	30.1	29.7	2.8	0.9	2.4	6.1	0.1	0.0	0.0	256455.3
	2012	25.5	37.0	17.1	3.3	0.7	8.6	7.7	0.1	0.0	0.0	350090.9
	2017	20.3	41.7	19.7	3.9	0.5	6.3	5.6	0.1	0.0	1.9	477853.8
TRP3	2003	26.8	20.5	52.1	2.5	0.3	0.0	0.0	0.1	0.0	0.0	196970.3
	2007	32.5	26.5	37.1	2.8	0.6	0.0	5.2	0.1	0.0	0.0	256455.3
	2012	29.4	30.7	24.3	3.3	0.7	7.8	7.7	0.1	0.0	0.0	350090.9
	2017	24.7	34.3	27.1	3.9	0.5	6.3	5.6	0.1	0.0	1.9	477853.8

Table 2.5b: Generation mix by plant types for IRP cases

Generation Expansion Planning Case		Generation mix (%)										Total Generation (GWh)
		Hydro	Coal	CCGT	Nuclear	Lignite	PFBC	IGCC	Wind	Solar	Biomass	
IRP	2003	27.7	31.9	32.9	2.5	0.6	0.0	0.0	0.1	0.0	0.0	191450.6
	2007	33.2	34.2	25.3	2.0	1.0	0.0	0.0	0.1	0.0	0.0	243146.7
	2012	30.6	42.0	16.8	1.6	0.8	0.5	0.0	0.1	0.0	0.0	298476.0
	2017	26.4	46.3	18.4	1.3	0.7	0.8	0.0	0.1	0.0	0.0	370241.8
IRP1	2003	25.2	34.1	37.5	2.5	0.6	0.0	0.0	0.1	0.0	0.0	191450.6
	2007	29.3	36.5	24.6	2.9	1.0	0.0	5.5	0.1	0.0	0.0	243146.7
	2012	29.6	45.5	15.6	3.9	0.8	0.0	4.4	0.1	0.0	0.0	298476.0
	2017	26.2	48.4	17.9	3.2	0.7	0.0	3.6	0.1	0.0	0.0	370241.8
IRP2	2003	25.2	28.6	43.2	2.5	0.3	0.0	0.0	0.1	0.0	0.0	191450.6
	2007	29.3	32.4	28.3	2.9	1.0	0.0	5.5	0.1	0.0	0.4	243146.7
	2012	29.9	39.9	18.1	3.9	0.8	0.0	7.2	0.1	0.0	0.1	298476.0
	2017	26.2	43.7	18.4	5.0	0.7	0.0	5.8	0.1	0.0	0.1	370241.8
IRP3	2003	25.2	22.0	49.9	2.5	0.3	0.0	0.0	0.1	0.0	0.0	191450.6
	2007	29.3	26.9	34.7	2.9	0.5	0.0	5.5	0.1	0.0	0.0	243146.7
	2012	29.9	25.7	21.8	3.2	0.8	10.1	8.1	0.1	0.0	0.3	298476.0
	2017	24.7	34.3	27.1	3.9	0.5	6.3	5.6	0.1	0.0	1.9	370241.8

2.4.1.2 Technology options selected

Table 2.6 shows candidate plants selected for all the considered cases. It is noticed that Coal6 and solar plants are not selected in any of the cases. All units of Hydro power plants and wind power plants are fully selected in each of the cases for their low capital cost and operating cost. As the emission constraint is imposed, a reduction in number of selection of Coal4 plants has been observed with the increase in emission constraints; and this reduction is compensated by the selection of more number of nuclear plants and BIGCC plants. All units of PFBC and IGCC are fully selected in TRP cases, but for the IRP cases the number of units selected increases with decrease in the emission level. Number of plants

selected for the IRP cases significantly reduces compared to the TRP cases due to consideration of DSM options but this reduction is observed only for the Coal 4, nuclear, PFBC, IGCC and BIGCC i.e. for thermal plants only and not for the hydro plants.

Table 2.6: Technology options selected

	TRP	TRP 1	TRP 2	TRP3	IRP	IRP 1	IRP2	IRP3
Coal 4	60	53	50	50	60	57	50	35
Coal 6	0	0	0	0	0	0	0	0
CCGT	74	80	80	80	80	77	80	80
Nuclear	2	6	6	6	0	3	6	6
PFBC	10	10	10	10	2	0	0	10
IGCC	10	10	10	10	0	5	8	10
Wind	50	50	50	50	50	50	50	50
Solar	0	0	0	0	0	0	0	0
BIGCC	0	1	10	10	0	0	1	6
Hibra	2	2	2	2	2	2	2	2
K.Wangtoo	4	4	4	4	4	4	4	4
Palamaneri	4	4	4	4	4	4	4	4
Budhil	2	2	2	2	2	2	2	2
L.Nagpal	2	2	2	2	2	2	2	2
Kuther	2	2	2	2	2	2	2	2
A.Duhangan	2	2	2	2	2	2	2	2
Uhl st. III	2	2	2	2	2	2	2	2
M.Bali	4	4	4	4	4	4	4	4
T. Vishnugadh	3	3	3	3	4	3	3	3
Parbati III	3	3	3	3	3	3	3	3
Dhauliganga II	3	3	3	3	3	3	3	3
Kishanganga	3	3	3	3	3	3	3	3
Kotlibhel	4	4	4	4	4	4	4	4
Uri II	4	4	4	4	4	4	4	4
Bursar	4	4	4	4	4	4	4	4
S.Kandi	1	1	1	1	1	1	1	1
Sewa st II	2	2	2	2	2	2	2	2
Pakhaldul	4	4	4	4	4	4	4	4
Kishau	5	5	5	5	5	5	5	5
Parbati I	3	3	3	3	3	3	3	3

2.4.1.3 Capacity utilization of the system

Table 2.7 shows capacity utilization of the system for each planning year and also average for all the cases. Average capacity utilization increases with the decrease in emission level. It is highest for the case with 15% reduction in emission level. Average capacity utilization for the TRP cases is more than the respective IRP cases.

Table 2.7: Capacity utilization of the system

Year	Generation Expansion Planning Cases							
	TRP	TRP 1	TRP 2	TRP 3	IRP	IRP 1	IRP 2	IRP 3
2003	50.46	50.46	50.46	49.35	49.88	49.88	49.88	49.60
2007	50.97	51.33	51.51	51.55	50.52	50.52	50.85	50.74
2012	52.20	51.88	52.37	52.68	48.46	48.35	48.70	49.61
2017	52.2	52.13	52.28	52.28	45.95	45.79	45.98	46.46
Average	51.75	51.78	52.10	52.12	48.48	48.56	48.76	49.21

2.4.1.4 Reliability of electricity generation system

Table 2.8 exhibits relative comparison of reliability expressed in terms of unserved energy in MWh of electricity generation system each year and average for all the considered cases. Average unserved energy is decreasing with the reduction in CO_2 emission and hence the reliability of the system improves. Also average unserved energy for the TRP cases is less than the corresponding IRP cases.

Table 2.8: Unserved Energy

Year	Unserved Energy (MWh)							
	TRP	TRP 1	TRP 2	TRP 3	IRP	IRP 1	IRP 2	IRP 3
2003	30.01	30.01	30.01	3.38	45.424	45.424	45.424	27.089
2007	2.202	2.156	1.493	1.686	40.558	20.136	30.779	25.802
2012	0.766	1.117	0.302	0.113	34.664	37.87	13.206	2.828
2017	0.001	0.001	0.001	0.001	6.090	5.109	3.584	2.478
Average	5.782	6.752	6.166	3.666	26.769	25.431	20.789	16.003

2.4.1.5 Change in fuel price:

➢ Change in coal price:

It can be observed from Table 2.9 that increasing the coal price does not make any significant difference to the technology options selected from the base case. Increasing the coal price increases the selection of nuclear plants where it was not fully selected and decreases the selection of IGCC plants in some cases like IRP1.

Table 2.9: Effect of change in coal price on technology options selected

	+10%								-10%							
	TRP	TRP 1	TRP 2	TRP 3	IRP	IRP 1	IRP 2	IRP 3	TRP	TRP 1	TRP 2	TRP 3	IRP	IRP 1	IRP 2	IRP 3
Coal 4	60	58	50	50	60	57	47	35	60	53	50	50	60	59	48	35
Coal 6	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0
CCGT	70	80	80	80	80	79	80	80	75	80	80	80	68	68	75	80
Nuclear	6	6	6	6	0	5	6	6	0	6	6	6	0	3	5	6
PFBC	9	6	10	10	2	0	2	10	10	10	10	10	8	0	3	10
IGCC	10	10	10	10	0	2	8	10	10	10	10	10	0	7	10	10
Wind	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BIGCC	0	0	10	10	0	0	2	6	0	1	10	10	0	2	0	5
Hibra	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
K.Wangtoo	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Palamaneri	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Budhil	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
L.Nagpal	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Kuther	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
A.Duhangan	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Uhl st. III	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
M.Bali	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
T. Vishnugadh	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Parbati III	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Dhauliganga II	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Kishanganga	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3

Kotlibhel	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Uri II	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Bursar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
S.Kandi	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Sewa st II	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Pakhaldul	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Kishau	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Parbati I	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3

2.5.1.5 Change in power demand:

Table 2.10 and 2.11 shows effect of change in power demand on utility planning. Demand could be increased by only 5% of the base case for TRP and IRP cases, as 10% increase in demand was not feasible for the given data. . Hence for these two cases only one sensitivity analyses has been done with the 20% decrease in demand. Demand has been decreased by 20% of the base case for all the cases. It can be observed from the tables that more number of all kind of plants are being selected as the demand increases. All the nuclear, PFBC and IGCC plants are selected for the TRP cases and their number increases for the IRP cases when the demand increases. For the IRP cases, the increase in power demand sees a decline in the selection of Coal4 plants and this is being compensated by increase in the DSM options. With the decrease in power demand, a decrease in the number of all type of plants has been noticed except for Coal4 plants for TRP cases as they are the most economical plants. Major reduction has been observed in CCGT plants due to their higher fuel cost. Solar plants are fully selected in case of TRP2 with the 5% increase in power demand. Number of units of nuclear plants selected becomes zero when other efficient technologies like PFBC, IGCC and wind power plants are available. All the hydro plants are selected even for reduction in the power demand.

Table 2.10: Effect of change in power demand on technology options selected for TRP cases

	TRP(+2%)	TRP(+5%)	TRP 1(+2%)	TRP 1(+5%)	TRP 2(+2%)	TRP 2(+5%)	-20%			
							TRP	TRP 1	TRP 2	TRP3
Coal 4	60	60	60	60	55	59	60	59	60	60
Coal 6	0	5	5	2	0	3	0	0	0	0
CCGT	77	80	80	80	80	80	25	23	23	25
Nuclear	5	6	6	6	6	6	0	0	0	0
PFBC	10	10	10	10	10	10	3	3	2	2
IGCC	10	10	10	10	10	10	0	2	2	1
Wind	50	50	50	50	50	50	50	50	50	50
Solar	0	0	0	0	0	50	0	0	0	0
BIGCC	0	0	0	10	10	10	0	0	0	0
Hibra	2	2	2	2	2	2	2	2	2	2
K.Wangtoo	4	4	4	4	4	4	4	4	4	4
Palamaneri	4	4	4	4	4	4	4	4	4	4
Budhil	2	2	2	2	2	2	2	2	2	2
L.Nagpal	2	2	2	2	2	2	2	2	2	2
Kuther	2	2	2	2	2	2	2	2	2	2
A.Duhangan	2	2	2	2	2	2	2	2	2	2
Uhl st. III	2	2	2	2	2	2	2	2	2	2
M.Bali	4	4	4	4	4	4	4	4	4	4
T. Vishnugadh	3	3	3	3	3	3	3	3	3	3
Parbati III	3	3	3	3	3	3	3	3	3	3
Dhauliganga II	3	3	3	3	3	3	3	3	3	3
Kishanganga	3	3	3	3	3	3	3	3	3	3
Kotlibhel	4	4	4	4	4	4	4	4	4	4
Uri II	4	4	4	4	4	4	4	4	4	4
Bursar	4	4	4	4	4	4	4	4	4	4
S.Kandi	1	1	1	1	1	1	1	1	1	1
Sewa st II	2	2	2	2	2	2	2	2	2	2
Pakhaldul	4	4	4	4	4	1	4	4	4	4
Kishau	5	5	5	5	5	5	5	5	5	5
Parbati I	3	3	3	3	3	3	3	3	3	3

Table 2.11: Effect of change in power demand on technology options selected for IRP cases

	IRP(+2%)	IRP(+5%)	IRP 1(+2%)	IRP 1(+5%)	IRP 2(+2%)	IRP 2(+5%)	-20%			
							IRP	IRP 1	IRP 2	IRP3
Coal 4	60	60	55	46	41	44	42	38	38	38
Coal 6	0	0	0	0	0	1	0	0	0	0
CCGT	80	80	80	80	80	80	32	37	37	37
Nuclear	0	1	5	6	6	6	0	1	1	0
PFBC	6	10	0	10	6	10	1	1	1	1
IGCC	0	2	8	10	10	10	0	0	0	0
Wind	50	50	50	50	50	50	50	50	50	50
Solar	0	0	0	0	0	0	0	0	0	0
BIGCC	0	0	0	8	3	10	0	0	0	0
Hibra	2	2	2	2	2	2	2	2	2	2
K.Wangtoo	4	4	4	4	4	4	4	4	4	4
Palamaneri	4	4	4	4	4	4	4	4	4	4
Budhil	2	2	2	2	2	2	2	2	2	2
L.Nagpal	2	2	2	2	2	2	2	2	2	2
Kuther	2	2	2	2	2	2	2	2	2	2
A.Duhangan	2	2	2	2	2	2	2	2	2	2
Uhl st. III	2	2	2	2	2	2	2	2	2	2
M.Bali	4	4	4	4	4	4	4	4	4	4
T. Vishnugadh	3	3	3	3	3	3	3	3	3	3
Parbati III	3	3	3	3	3	3	3	3	3	3
Dhauliganga II	3	3	3	3	3	3	3	3	3	3
Kishanganga	3	3	3	3	3	3	3	3	3	3
Kotlibhel	4	4	4	4	4	4	4	4	4	4
Uri II	4	4	4	4	4	4	4	4	4	4
Bursar	4	4	4	4	4	4	4	4	4	4
S.Kandi	1	1	1	1	1	1	1	1	1	1
Sewa st II	2	2	2	2	2	2	2	2	2	2
Pakhaldul	4	4	4	4	4	4	4	4	4	4
Kishau	5	5	5	5	5	5	5	5	5	5
Parbati I	3	3	3	3	3	3	3	3	3	3

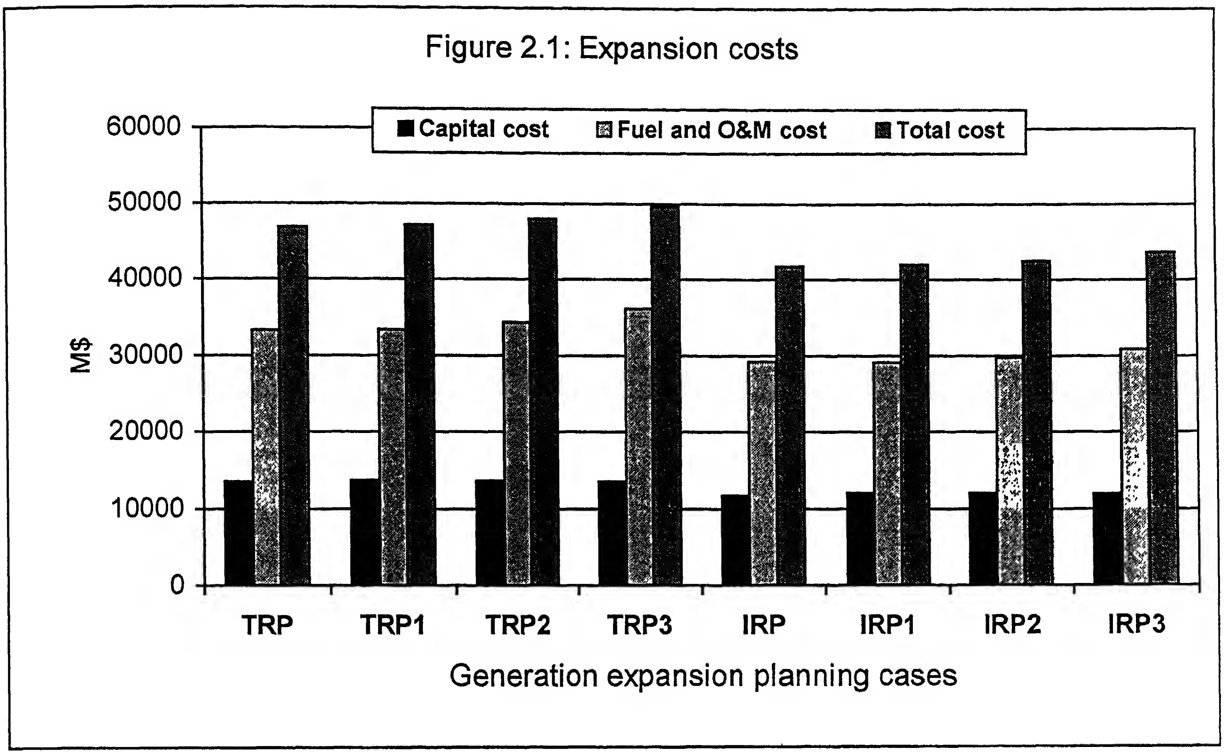
2.4.1.7 Cost and Pricing Implications

➢ **Expansion costs during the planning horizon:**

Expansion cost for all the cases during the planning horizon are shown in Table 2.12. Capital cost is highest for TRP1 and IRP1 cases and decreases with the decrease in emission level due to less number of Coal4 units being selected, but fuel and variable costs increases due to the higher cost of gas. Fixed O&M cost does not show any specific trend and also does not vary significantly for different cases. Total cost increases with the decrease in emission level, because increment in fuel and variable cost is more than decrement in capital cost. Capital cost, fixed O&M, fuel and variable cost are much less for the IRP cases than the TRP cases. Total cost for the IRP cases is less than the TRP cases even after including DSM cost. Figure 2.1 shows a comparison between capital cost, fuel and variable cost and total cost including DSM cost for all the eight cases.

Table 2.12: Expansion costs during planning horizon

Expansion costs (M$)	Generation expansion planning cases							
	TRP	TRP1	TRP2	TRP3	IRP	IRP 1	IRP 2	IRP3
Capital cost (1)	13519.6	13723.6	13633.3	13522.3	11739.6	12054.8	12049.3	11985.1
Fixed O&M (2)	6848.0	6880.1	6845.0	6858.4	6519.9	6554.17	6551.4	6513.2
Fuel and Variable (3)	26388.6	26474.3	27481.5	29219.5	22717.7	22601.3	23129.4	24341.7
Fuel and O&M (2+3)	33236.6	33354.4	34326.5	36077.9	29237.6	29155.4	29680.8	30854.9
Sub total (1+2+3)	46756.2	47078.0	47960.0	49600.2	40977.3	41210.2	41730.2	42840.0
DSM cost (4)	0	0	0	0	707.5	707.5	707.5	707.5
Total Cost (1+2+3+4)	46756.2	47078.0	47960.0	49600.2	41684.8	41917.7	42437.7	43547.5



2.4.1.8 Electricity prices:

Electricity price for all the considered cases are shown in Table 2.13. It shows that electricity price is highest for the TRP case. With the introduction of clean efficient technology in the other cases and DSM options in IRP cases, electricity price reduces compared to the TRP cases. Electricity price increases for IRP cases when DSM cost is included but it still remains lower than the corresponding TRP cases.

Table 2.13: Electricity price for expansion planning cases

Electricity price (US cents/kWh)	Generation expansion planning cases							
	TRP	TRP1	TRP2	TRP3	IRP	IRP1	IRP2	IRP3
Without DSM	2.86	2.83	2.79	2.60	2.68	2.62	2.47	2.21
With DSM	2.86	2.83	2.79	2.60	2.87	2.80	2.65	2.40

2.4.2 Environmental Implications

2.4.2.1 Total environmental emissions:

Table 2.14 shows CO_2, SO_2 and NO_x emissions from all the eight cases considered in the planning horizon. Table 2.15 shows emission mitigation of the pollutants due to the introduction of emission constraints on CO_2. Although, emission limit is imposed only on CO_2 emissions, the emission of SO_2 and NO_x also reduces due to the reduction in number of Coal4 plants selected. Figure 2.2 shows the comparison between CO_2, SO_2 and NO_x emissions for all the six cases

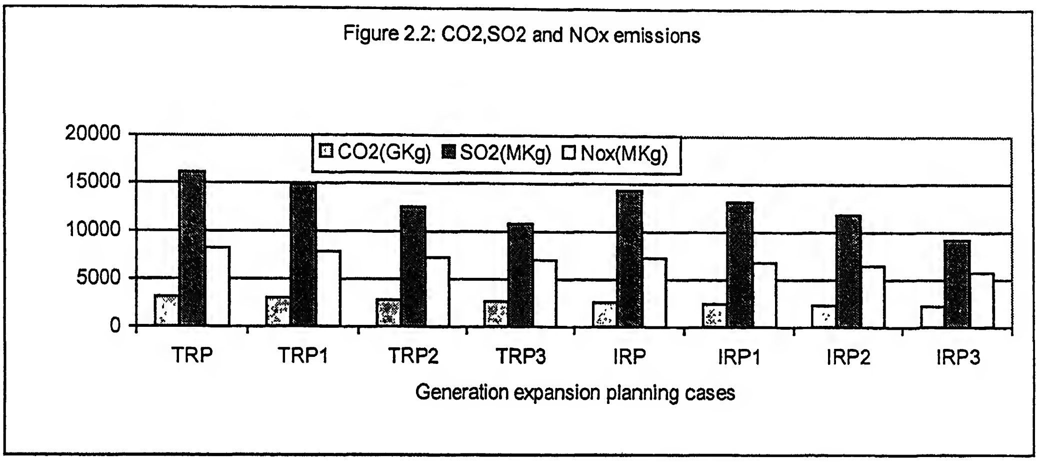


Table 2.14: Total environmental emissions

Emission	Generation expansion planning cases							
	TRP	TRP 1	TRP 2	TRP3	IRP	IRP 1	IRP2	IRP3
CO_2 (Gkg)	3166.1	3006.6	2849.1	2690	2628.5	2491.1	2365.1	2234.3
SO_2 (Mkg)	16083	14847	12571	10818	14339	13125	11792	9175.5
NO_x (Mkg)	8234.7	7839.3	7279.3	6975	7270	6827.3	6466.7	5753.4

Table 2.15: Total environmental emission mitigation

Emissions	Abatement of emissions from respective base cases					
	5%Abatement		10% Abatement		15% Abatement	
	TRP1	IRP1	TRP2	IRP2	TRP3	IRP3
CO_2 (Gkg)	159.5	137.4	317.0	263.5	476.1	394.2
SO_2 (Mkg)	1236	1214	3512	2547	5265	5163.5
NO_x (Mkg)	395.4	442.7	955.4	803.3	1259.7	1516.6

2.5 CONCLUSIONS

On the basis of the studies carried out on Northern Regional Electricity Board (NREB) in India, and results obtained from the generation expansion planning as well as various sensitivity analyses performed for the above cases, following main conclusions can be drawn.

- All candidate hydro plants are fully selected in all the above eight cases due to their low capital cost, no operating cost and zero emissions.
- Solar plants are not selected in any of the cases due to their higher capital cost.Wind plants are fully selected in all the cases due to their low capital cost and low operating cost.
- Coal6 plants are not selected in most of the cases due to their high fuel cost.
- Number of coal4 units selected decreases as the emission constraint is imposed for all the cases. This decrease is more for the IRP cases.
- Average capacity utilization increases with the decrease in emission level. Average unserved energy decreases with the reduction in CO_2 emission level. Thus, system becomes more reliable with the increase in emission limit due to the introduction of additional efficient / clean supply side options.
- Total expansion cost increases with increase in emission limit and for the IRP cases it is less than the TRP cases. Maximum electricity price is obtained for the IRP base case among all the cases considered. Electricity price decreases with reduction in emission limit for both TRP and IRP cases. The electricity prices for the IRP cases are lower than the TRP cases.
- Emission level of SO_2 and NO_x also decreases with emission constraint imposed on CO_2 level.
- Reduction in coal price has overall effect of reducing the total cost and increasing the emission level. Increase in coal price has the reverse effect.
- Increasing the power demand increases the selection of nuclear, PFBC and IGCC plants, increases the cost and increases the emission level of pollutants. Decreasing the demand has the reverse effect.

CHAPTER 3

IMPLICATION OF CARBON TAX IN UTILITY AND ELECTRICITY GENERATION EXPANSION PLAN

3.1 INTRODUCTION

The previous chapter-2 has addresses the issue of reducing carbon dioxide emission from power plants to a predecided target value and their impact on generation technology shift cost and environmental implications. No economic/ financial instrument was considered in the CO_2 reduction.

Any significant reduction in carbon emissions may involve elimination of existing subsidies on fossil fuels to achieve the actual production cost. As such, carbon tax [2,3] has attracted attention and commonly recognized as an economic instrument in achieving emission mitigation. Therefore, it is imperative to assess the potential role of carbon tax on GHG and other harmful environmental emissions.

The main reason for using carbon tax is to bring the costs of pollution into the price of the goods and services produced by economic activity. By levying tax on CO_2 emissions, and burning of fossil fuels, consumers are motivated to utilize energy more efficiently to reduce energy consumption wherever possible and to substitute away from most CO_2-generating fuels. Also imposition of tax lead to cost-effective allocation of CO_2 emissions. The taxes, in addition to reducing GHG emissions are the additional revenue generation.

In this chapter, an analysis of the environmental and utility planning implications of carbon tax has been provided. The analysis also includes few important factors associated with generation expansion planning like capacity mix, generation mix, capacity factor and unserved energy at different carbon tax and electric price elasticity. Sensitivity analyses have also been done with respect to few parameters associated with the candidate plants.

3.2 METHODOLOGY

The aim of this study is to estimate the change in environmental emissions with the introduction of carbon tax [2]. The carbon tax is a duty levied on fossil fuels proportionate to their carbon contents. Therefore, imposing carbon tax would increase the fuel cost. Thus, electricity industry would face higher prices for coal, gas and fuel oil and will choose to burn different fuels according to their relative prices. Also any increase in fuel cost would affect the utility in their system cost, generation and capacity mix. In addition, levy of carbon tax not only affect the electricity generation supply side but also reduces the demand for electricity due to increase of electricity price. Furthermore, carbon tax effect CO_2 emission through both supply and demand side responses [Appendix E]. The supply side response takes place in form of inter-fuel and technological substitutions in power generation, while demand-side response occurs in the form of reductions in electricity demand due to increase in electricity price after introducing carbon tax. The methodology to calculate the technology substitution effect and price effect of carbon tax are given in Appendix-E.

Thus, CO_2 emission is expected to decline as a result of less electricity generation and use of cleaner fuel. A least cost integrated resource planning (IRP) model [7] has been used to calculate the changes in generation- and fuel mixes with changes in relative costs of different power generation options due to carbon tax and corresponding changes in electricity price. For a change in electricity price, the corresponding change in electricity demand can be derived using price elasticity of demand. A flow chart given in fig.3.1 has been used to study the impact of carbon tax[2].

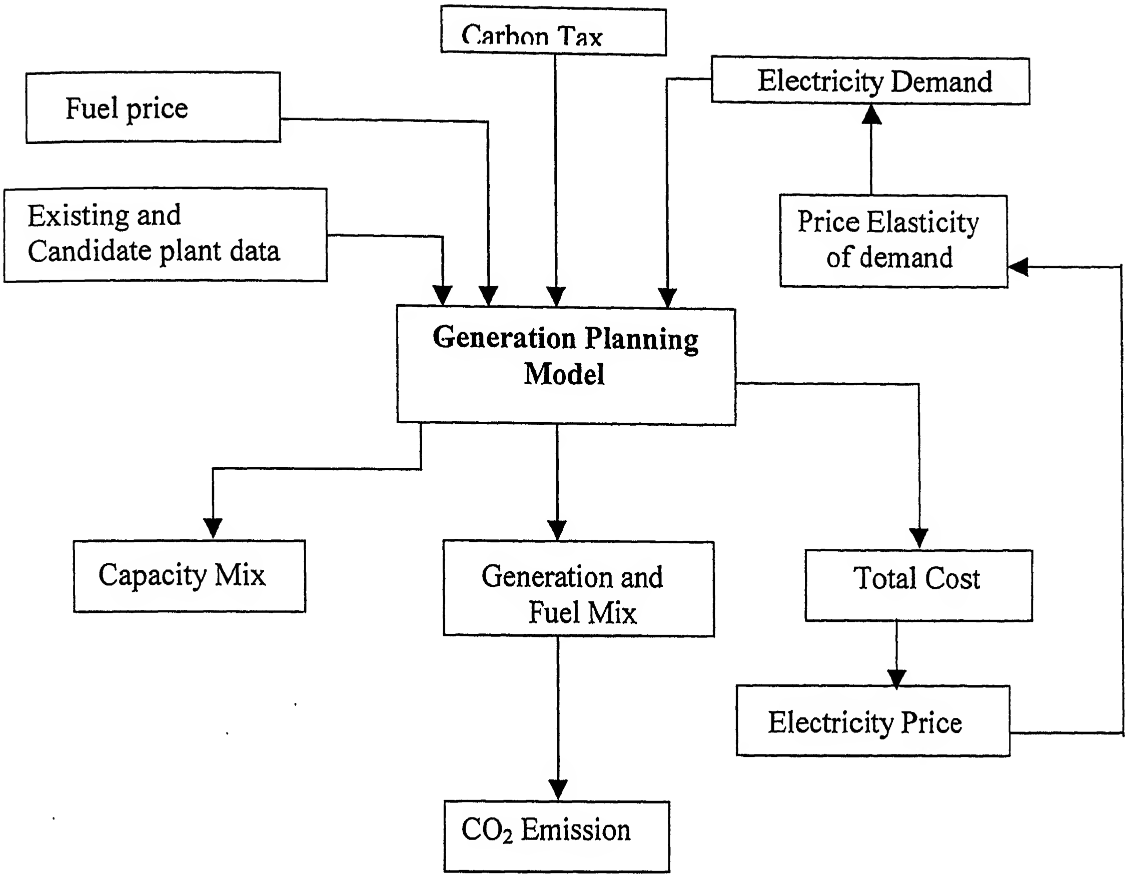


Figure 3.1. Flowchart for assessment of environmental and utility planning implications with carbon tax in generation expansion planning

Major steps involved in finding the equilibrium levels of electricity price and energy demand after introduction of carbon tax are given below.

Step 1. First, run the IRP model to find electricity price (P_0) at the level of forecasted demand (Q_0) without imposition of any carbon tax.

Step 2. Rerun the IRP model with a carbon tax. The tax will cause electricity Price toincrease up to a new price (P_1).

Step 3. Find the new level of demand (Q_1) at the new electricity price (P_1) through price elasticity curve.

Step 4. At this level of demand (Q_1), rerun IRP model to find again the electricity price (P_2)

Step 5. Find the new level of demand (Q_2) at the new electricity price (P_2) through price elasticity curve.

Step 6. The above iterative process is repeated till; the demand and electricity price converges to a single equilibrium point (p_{eq}, Q_{eq}).

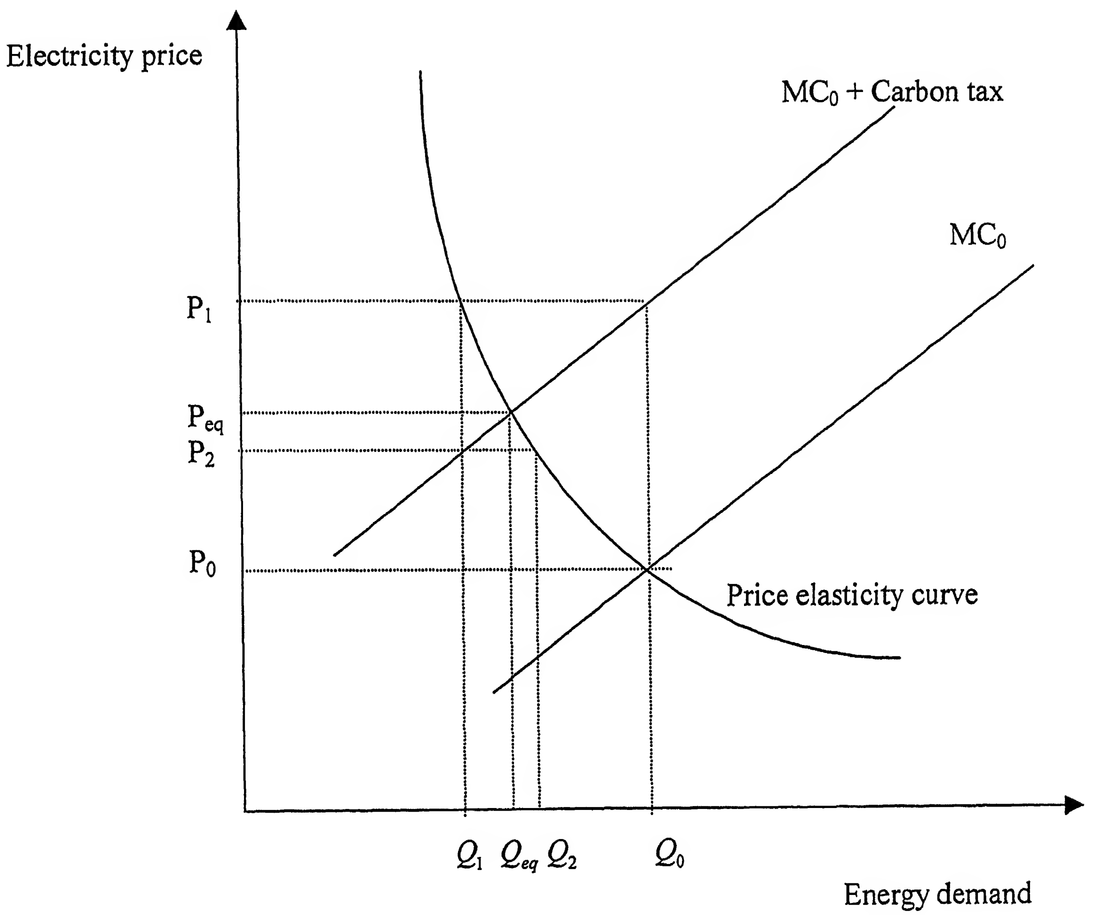


Figure 3.2. Graph shows relation between electricity price and energy demand

At the base case, the energy demand (Q_0) in GWh would be

$$Q_0 = \Sigma\ Q_n = \Sigma\ MW_{0,n} \times LF_n \times 8.76 \qquad (3.1)$$

where $MW_{0,n}$ = peak MW of year n

LF = Load factor for year n.

n = no of year

Q_n = Energy demand in year-n

Therefore, the average demand (GWh) in any year is

$$Q_{n,average} = MW_{peak} \times LF_n \times 8.76 \tag{3.2}$$

The electricity prices without carbon tax say (P_0) and with carbon taxes say (P_1) are:

$$P_0 = AIC_{0,gen} + AIC_{0,transmission} + AIC_{0,distribution}$$

$$P_1 = AIC_{1,gen} + AIC_{1,transmission} + AIC_{1,distribution}$$

and change in price from base case (without carbon tax)

$$\Delta P = P_0 - P_1 = AIC_{0,gen} - AIC_{1,gen}$$

where

LF = Load Factor = Average demand / Maximum demand

AIC = Average Incremental Cost

It is assumed that AIC for transmission & distribution will remain same at different load values. Hence,

$$AIC_{0,transmission} = AIC_{1,transmission}$$

$$AIC_{0,distribution} = AIC_{1,distribution}$$

The price elasticity (e_p) for electricity demand can be defined as the ratio of percentage change in electricity demand to the percentage change in electricity price [38].

$$e_p = \frac{P_0 \times \Delta Q}{Q_0 \times \Delta P}$$

change in demand (ΔQ)can be computed as;

$$\Delta Q = \frac{e_p \times \Delta P \times Q_0}{P_0}$$

and new demand as;

$$Q_1 = Q_0 - \Delta Q$$

Where Q_1 is the new demand upon levy of the carbon tax. Considering the same rate of the energy demand reduction say (X%) from Q_0 to Q_1, the peak load (MW_{peak}) for each year

is assumed to decrease by same percentage as Q_0 is reduced to Q_1. So, the total energy demand at the new price (Q_1) can be obtained using Equation (3.2), that is,

$$Q_1 = MW_{1,peak} \times LF \times 8.76$$

The new demand value will provide new generation planning results. The above process has been repeated to determine the different prices and energy demand till both converge to a single point, which is the new electricity price and demand. The process can be repeated to determine the different prices and energy demand for different value of carbon tax imposed and also different price elasticity constant values.

The study has considered a planning horizon of 15 years starting from year 2003 to 2017. Electricity demand, energy requirement and load factor forecasting for NREB system has been taken from 16th Electric Power Survey (EPS) of India.In the present study also, most of the data are consistent with the norms used in India for power generation expansion planning. The assumptions made in this study are listed below:

1. The planning horizon is taken as 2003-2017, base year is considered as 1998 and discount rate as 10%. Reserve margin is taken as 5% for all the years. Transmission loss rate is taken as 4%.
2. Twenty blocks are taken in one season and two seasons are considered in one year. Season 1 is of total 92 days (July, August and September) and seasons 2 (rest of the months) consist of total 273 days. All costs are taken for the base year of 1998.
3. Minimum operating capacity is taken as 30% of the installed capacity for thermal power plants. Operating cost is taken as 1% of the total capital cost and fixed operating and maintenance (O&M) cost as 2.5% for thermal plants. Operating cost for hydro plants is assumed to be zero and fixed O&M cost is taken as 1.5% of the total capital cost.

Total ten types of fuels have been taken for thermal plants, which are gas, nuclear, lignite, oil and six types of coal based on their relative cost. Four types of thermal power plants with one IPP plant based on coal and twenty-three types of hydro power plants including four hydro IPP plants are considered as candidate plants. All considered thermal

and hydro candidate plants are given in appendix B. In the NREB, there are eight existing thermal IPP plant units and eight existing hydro IPP plant units. All these existing and candidate IPP power plants are given in Appendix C.

3.3 RESULTS AND DISCUSSIONS

The generation planning studies using methodology described in section 3.2 were carried out for the following cases.

1. Generation expansion planning without carbon tax.
2. Generation expansion planning with carbon tax at different rates per ton of carbon (10\$, 50\$, 100\$, 200\$) and for different Price elasticity (e_p) values (–0.1, -0.2 and -0.5)
3. Different value of carbon tax have been considered in the form of increase in fuel price taken as input to the IRPA software. If 'CT' is the amount of carbon tax in \$/ton. And heat rate 'HR' of a fuel in Kbtu/Kg

   Increase in fuel price in \$/Gcal = $CT/(HR)_i \times 0.252$ (\$/Gcal)

3.3.1 Utility Planning Implications

(a) Capacity mix and Generation mix

Table 3.1 shows capacity mix by plant type for different carbon taxes and at different price elasticity (-0.1, -0.2 and –0.5). It shows that, during the planning horizon, with the introduction of carbon tax the hydro power plant capacity mix increases in each year with all level of carbon taxes. This is due to the fact that all candidate power plants, which got selected, were of hydro type. The selection of candidate thermal power plants having coal as a fuel decreases as we increase the level of carbon tax. The hydrothermal mix is highest in 2007 as all the candidate hydro plants are get selected in this year.

Table 3.1c shows that at high price elasticity of –0.5 and with carbon tax 100$/ton and 200$/ton, none of the plants got selected because demand became zero. So it is not practically feasible to impose such a high carbon tax at higher price elasticity.

Table 3.1 a: Capacity mix for price elasticity = –0.1

Generation Expansion Planning Case		Capacity mix (%)					Total Capacity (MW)
		Hydro	Coal	CCGT	Nuclear	Lignite	
Base Case	2003	28.0	31.0	38.1	2.4	0.5	44527.56
	2007	30.5	36.6	29.4	2.7	0.8	58431.69
	2012	27.3	47.0	21.9	3.2	0.6	79544.68
	2017	23.4	49.9	22.6	3.7	0.4	108989.98
With Ctax 10$/ton	2003	28.4	31.3	37.4	2.4	0.5	44024.06
	2007	31.1	36.4	29.0	2.7	0.8	57513.79
	2012	27.8	40.2	28.1	3.3	0.6	78039.14
	2017	23.5	49.4	22.9	3.8	0.4	107768.56
With Ctax 50$/ ton	2003	29.4	32.4	35.2	2.5	0.5	42583.33
	2007	32.6	30.0	33.7	2.9	0.8	54620.00
	2012	29.2	35.4	31.4	3.4	0.6	74536.72
	2017	24.7	47.0	24.0	3.9	0.4	102948.94
With Ctax 100$/ ton	2003	29.8	32.8	34.4	2.5	0.5	42064.02
	2007	32.8	29.2	34.3	2.9	0.8	54342.46
	2012	30.6	32.2	33.0	3.6	0.6	71074.53
	2017	25.7	44.6	25.1	4.1	0.5	98399.10
With Ctax 200$/ ton	2003	31.3	34.7	30.7	2.7	0.6	39760.80
	2007	34.7	30.9	30.5	3.0	0.9	51411.00
	2012	33.9	24.8	36.6	4.0	0.7	64056.45
	2017	29.1	37.6	28.2	4.6	0.5	87462.76

Table 3.1 b: Capacity mix for price elasticity = –0.2

Generation Expansion Planning Case		Capacity mix (%) Hydro	Coal	CCGT	Nuclear	Lignite	Total Capacity (MW)
Base Case	2003	28.0	31.0	38.1	2.4	0.5	44527.56
	2007	30.5	36.6	29.4	2.7	0.8	58431.69
	2012	27.3	47.0	21.9	3.2	0.6	79544.68
	2017	23.4	49.9	22.6	3.7	0.4	108989.98
With Ctax 10$/ ton l	2003	28.7	31.7	36.7	2.4	0.5	43523.65
	2007	31.6	36.1	28.7	2.8	0.8	56470.91
	2012	28.1	40.6	27.4	3.3	0.6	77305.41
	2017	23.9	48.7	23.2	3.8	0.4	106542.09
With Ctax 50$/ ton	2003	30.8	34.0	32.0	2.6	0.6	40579.41
	2007	34.3	30.6	31.2	3.0	0.9	51915.03
	2012	30.6	32.2	33.0	3.6	0.6	71074.53
	2017	25.9	44.3	25.2	4.1	0.5	97936.79
With Ctax 100$/ ton	2003	31.8	35.1	29.8	2.7	0.6	39307.69
	2007	35.0	31.2	29.8	3.1	0.9	50916.66
	2012	33.8	24.8	36.6	4.1	0.7	64056.45
	2017	28.6	38.3	27.9	4.7	0.5	87787.56
With Ctax 200$/ ton	2003	36.7	40.5	19.0	3.1	0.7	34066.66
	2007	40.6	36.2	18.6	3.6	1.0	43883.97
	2012	39.4	28.7	26.5	4.6	0.8	55351.91
	2017	36.1	22.5	35.0	5.8	0.6	70604.44

Table 3.1 c: Capacity mix for price elasticity = –0.5

Generation Expansion Planning Case		Capacity mix (%) Hydro	Coal	CCGT	Nuclear	Lignite	Total Capacity (MW)
Base Case	2003	28.0	31.0	38.1	2.4	0.5	44527.56
	2007	30.5	36.6	29.4	2.7	0.8	58431.69
	2012	27.3	47.0	21.9	3.2	0.6	79544.68
	2017	23.4	49.9	22.6	3.7	0.4	108989.98
With Ctax 10$/ ton	2003	29.6	32.6	34.8	2.5	0.5	42322.08
	2007	32.6	36.4	27.3	2.9	0.8	54631.86
	2012	29.2	41.4	25.4	3.4	0.6	74603.86
	2017	24.7	47.0	24.0	3.9	0.4	102948.94
With Ctax 50$/ ton	2003	35.4	39.1	21.9	3.0	0.6	35286.44
	2007	39.4	35.2	20.9	3.5	1.0	45130.68
	2012	36.0	26.2	32.9	4.2	0.7	60633.58
	2017	39.4	34.6	20.6	4.9	0.5	83485.54
With Ctax 100$/ ton	2003	0.0	0.0	0.0	0.0	0.0	0.0
	2007	0.0	0.0	0.0	0.0	0.0	0.0
	2012	0.0	0.0	0.0	0.0	0.0	0.0
	2017	0.0	0.0	0.0	0.0	0.0	0.0
With Ctax 200$/ ton	2003	0.0	0.0	0.0	0.0	0.0	0.0
	2007	0.0	0.0	0.0	0.0	0.0	0.0
	2012	0.0	0.0	0.0	0.0	0.0	0.0
	2017	0.0	0.0	0.0	0.0	0.0	0.0

Table 3.2a, 3.2b, and 3.2c show the generation mix of all types of plants for different carbon tax (10, 50, 100, and 200 in \$/ton of carbon content of fuel), at different Price elasticity values (-0.1, -0.2 and –0.5). The share of nuclear and hydro plants (in %) continuously increased every year because if we impose carbon tax, then all candidate nuclear and hydro power plants get selected. The total generation (MWh) decreases as we increase the level of carbon tax and price elasticity, the price of electricity goes up and demand decreases. The share of coal based power plants (in %) decreased as the higher carbon tax was imposed

Table 3.2a: Generation mix with price elasticity = –0.1

Generation Expansion Planning Case		Generation mix (%)					Total Generation (GWh)
		Hydro	Coal	CCGT	Nuclear	Lignite	
Base Case	2003	25.1	37.0	34.8	2.5	0.6	196948.65
	2007	26.6	45.1	25.5	1.9	0.9	256483.37
	2012	24.4	57.6	14.0	3.3	0.7	350416.67
	2017	19.5	61.7	14.4	3.9	0.5	477906.00
With Ctax 10\$/ ton	2003	25.4	36.4	35.1	2.5	0.6	194156.59
	2007	26.9	43.7	25.6	2.8	1.0	253086.96
	2012	24.7	48.9	22.3	3.4	0.7	345699.39
	2017	19.9	61.1	14.6	3.9	0.5	471715.22
With Ctax 50\$/ ton l	2003	26.2	25.5	45.4	2.6	0.3	186674.51
	2007	27.8	25.0	43.8	2.9	0.5	243344.00
	2012	25.5	29.5	41.1	3.5	0.4	331803.39
	2017	20.4	43.5	31.7	4.1	0.3	965029.41
With Ctax 100\$/ ton	2003	27.5	23.0	46.5	2.7	0.3	178473.91
	2007	29.1	20.7	46.6	3.1	0.5	232086.96
	2012	26.8	26.0	43.1	3.7	0.4	317026.92
	2017	21.4	40.7	33.3	4.3	0.3	431884.52
With Ctax 200\$/ ton	2003	30.6	23.0	43.0	3.0	0.4	160486.96
	2007	32.3	20.5	43.2	3.4	0.6	208439.02
	2012	29.8	17.6	48.1	4.1	0.4	285727.27
	2017	23.4	34.0	37.1	4.8	0.3	388214.71

Table 3.2b: Generation mix with price elasticity = –0.2

Generation Expansion Planning Case		Generation mix (%) Hydro	Coal	CCGT	Nuclear	Lignite	Total Generation (GWh)
Base Case	2003	25.1	37.0	34.8	2.5	0.6	196948.65
	2007	26.6	45.1	25.5	1.9	0.9	256483.37
	2012	24.4	57.6	14.0	3.3	0.7	350416.67
	2017	19.5	61.7	14.4	3.9	0.5	477906.00
With Ctax 10$/ ton	2003	25.8	36.8	34.3	2.5	0.6	192046.20
	2007	27.2	43.1	25.8	2.9	1.0	250160.09
	2012	25.1	49.5	21.3	3.4	0.7	341577.78
	2017	23.0	60.6	14.9	4.0	0.5	466166.67
With Ctax 50$/ ton	2003	27.6	27.8	41.6	2.7	0.3	177564.75
	2007	29.2	27.0	40.2	3.1	0.5	231596.30
	2012	26.8	25.9	43.2	3.7	0.4	316042.47
	2017	21.5	40.6	33.3	4.3	0.3	431014.78
With Ctax 100$/ ton	2003	30.2	25.3	41.1	3.0	0.4	162249.01
	2007	32.0	22.7	41.3	3.4	0.6	211303.96
	2012	29.4	18.8	47.3	4.1	0.4	287632.98
	2017	23.6	34.8	36.6	4.7	0.3	392752.87
With Ctax 200$/ ton	2003	38.9	29.1	27.6	3.9	0.5	125240.55
	2007	41.3	25.9	27.7	4.4	0.7	163038.61
	2012	38.0	18.8	37.4	5.3	0.5	223069.15
	2017	30.5	15.6	47.4	6.1	0.4	305083.33

Table 3.2c: Generation mix with price elasticity = –0.5

Generation Expansion Planning · Case		Generation mix (%) Hydro	Coal	CCGT	Nuclear	Lignite	Total Generation (GWh
Base Case	2003	25.1	37.0	34.8	2.5	0.6	196948.65
	2007	26.6	45.1	25.5	1.9	0.9	256483.37
	2012	24.4	57.6	14.0	3.3	0.7	350416.67
	2017	19.5	61.7	14.4	3.9	0.5	477906.00
With Ctax 10$/ ton	2003	26.5	38.0	32.2	2.6	0.7	185889.47
	2007	28.1	43.4	24.6	2.9	1.0	241976.96
	2012	25.9	50.3	19.6	3.5	0.7	330596.42
	2017	20.7	58.5	16.2	4.1	0.5	451382.91
With Ctax 50$/ ton	2003	31.8	36.9	27.7	3.2	0.4	153479.67
	2007	33.7	35.7	26.4	3.6	0.6	200319.33
	2012	31.0	22.0	42.3	4.3	0.4	272718.18
	2017	24.8	31.3	38.6	5.0	0.3	372638.98
With Ctax 100$/ ton	2003	00.0	00.0	00.0	00.0	0.0	00.0
	2007	00.0	00.0	00.0	00.0	0.0	00.0
	2012	00.0	00.0	00.0	00.0	0.0	00.0
	2017	00.0	00.0	00.0	00.0	0.0	00.0
With Ctax 200$/ ton	2003	00.0	00.0	00.0	00.0	0.0	00.0
	2007	00.0	00.0	00.0	00.0	0.0	00.0
	2012	00.0	00.0	00.0	00.0	0.0	00.0
	2017	00.0	00.0	00.0	00.0	0.0	00.0

Table 3.3: Technology options (Number of units) selected

	Base case	With P.E.-0.1& Different Ctax ($/ton)				With P.E.-0.2& Different Ctax ($/ton)				With P.E.-0.5& Different Ctax ($/ton)			
		10	50	100	200	10	50	100	200	10	50	100	200
Coal 4	60	60	60	55	34	59	54	35	0	60	26	0	0
Coal 6	17	13	5	1	0	12	1	1	0	5	0	0	0
CCGT	80	80	80	80	80	80	80	80	80	80	80	0	0
Nuclear	6	6	6	6	6	6	6	6	6	6	6	0	0
Jawaharpur TPP	0	0	0	0	0	0	0	0	0	0	0	0	0
Hibra	2	2	2	2	2	2	2	2	2	2	2	0	0
K.Wangtoo	0	0	0	0	0	0	0	0	0	0	0	0	0
Srinagar HEP	0	0	0	0	0	0	0	0	0	0	0	0	0
Palamaneri	4	4	4	4	4	4	4	4	4	4	4	0	0
Budhil	2	2	2	2	2	2	2	2	2	2	2	0	0
L.Nagpala	2	2	2	2	2	2	2	2	2	2	2	0	0
D. Sunda	0	0	0	0	0	0	0	0	0	0	0	0	0
Kuther	2	2	2	2	2	2	2	2	2	2	2	0	0
A.Duhangan	0	0	0	0	0	0	0	0	0	0	0	0	0
Uhl st. III	2	2	2	2	2	2	2	2	2	2	2	0	0
M.Bali	4	4	4	4	4	4	4	4	4	4	4	0	0
T. Vishnugadh	3	3	3	3	3	3	3	3	3	3	3	0	0
Parbati III	3	3	3	3	3	3	3	3	3	3	3	0	0
Dhauliganga II	3	3	3	3	3	3	3	3	3	3	3	0	0
Kishanganga	3	3	3	3	3	3	3	3	3	3	3	0	0
Kotlibhel	4	4	4	4	4	4	4	4	4	4	4	0	0
Uri II	4	4	4	4	4	4	4	4	4	4	4	0	0
Bursar	4	4	4	4	4	4	4	4	4	4	4	0	0
S.Kandi	1	1	1	1	1	1	1	1	1	1	1	0	0
Sewa st II	2	2	2	2	2	2	2	2	2	2	2	0	0
Pakhaldul	4	4	4	4	4	4	4	4	4	4	4	0	0
Kasha	5	5	5	5	5	5	5	5	5	5	5	0	0
Parbati I	3	3	3	3	3	3	3	3	3	3	3	0	0

(b) Technology options selected

Table 3.3 shows that all available hydro plants get selected for each of the considered cases as these have less O&M cost and zero fuel cost. With the imposition of carbon tax it is observed that the number of units of coal 4 and coal 6 as fuel were decreased. The number of units of nuclear and CCGT remained the same at all carbon tax and price elasticity value. For different price elasticity cases, a sharp decrease in number of coal 4 and coal 6 plants are observed at higher level of carbon tax, specifically at higher price elasticity values.

(C) Reliability of electricity generation system

Tables 3.4 a, b, and c exhibit relative comparison of reliability expressed in terms of unserved energy in MWh of electricity generation each year and also its average value for all the considered cases. The average unserved energy increases for carbon tax values of 10 \$/ton, 50 \$/ton but for carbon tax 100 \$/ton, 200 \$/ton, it decreases. For higher price elasticity values, the average unserved energy increases for carbon tax (10 \$/ton, 50 \$/ton) but it decreases very sharply for carbon tax (100 \$/ton, 200 \$/ton). Thus, average capacity utilization increases with the imposition of carbon tax.

Table 3.4a: Reliability of system with price elasticity –0.1

Year	Unserved energy (MWh)				
	Base Case	With Ctax (\$/ton)			
		10	50	100	200
2003	17.712	42.442	236.910	6.884	0.567
2004	14.032	45.028	23.703	2.471	0.014
2005	36.370	83.204	7.533	0.439	0.017
2006	2.788	7.494	25.330	0.028	0.000
2007	3.101	13.825	19.662	0.035	0.000
2008	25.691	3.005	1.841	0.262	0.018
2009	10.268	5.113	5.161	0.573	0.000
2010	0.513	0.744	4.548	1.014	0.006
2011	3.808	5.947	16.956	0.564	0.006
2012	1.466	0.307	2.038	12.528	0.074
2013	5.244	8.827	0.152	1.791	0.093
2014	0.055	0.018	1.378	1.791	1.593
2015	0.002	0.003	0.020	0.011	0.025
2016	2.326	3.122	0.000	0.081	3.690
2017	0.004	0.011	1.111	0.000	0.016
Aver.	6.468	10.663	15.696	1.630	0.520

Table 3.4b: Reliability of system with price elasticity –0.2

Year	Unserved energy (MWh)				
	Base Case	With Ctax ($/ton)			
		10	50	100	200
2003	17.712	103.871	462.398	3.626	0.001
2004	14.032	33.616	43.619	0.223	0.000
2005	36.370	244.765	340.769	0.535	0.000
2006	2.788	8.050	157.191	0.009	0.000
2007	3.101	32.745	40.200	0.003	0.000
2008	25.691	5.375	7.685	0.109	0.000
2009	10.268	6.974	52.084	0.011	0.000
2010	0.513	1.776	0.861	0.017	0.000
2011	3.808	17.853	1.082	0.009	0.000
2012	1.466	1.102	3.184	0.302	0.000
2013	5.244	0.005	0.690	0.052	0.000
2014	0.055	0.051	0.027	0.820	0.000
2015	0.002	0.001	0.102	0.026	0.000
2016	2.326	13.833	0.058	1.688	0.000
2017	0.004	0.032	1.358	0.007	0.000
Aver.	6.468	22.822	51.047	0.448	0.000

Table 3.4c: Reliability of system with price elasticity –0.5

Year	Unserved energy (MWh)				
	Base Case	With Ctax ($/ton)			
		10	50	100	200
2003	17.712	295.524	462.398	00.00	00.00
2004	14.032	79.947	43.619	00.00	00.00
2005	36.370	13.369	340.769	00.00	00.00
2006	2.788	92.055	157.191	00.00	00.00
2007	3.101	4.449	40.200	00.00	00.00
2008	25.691	11.175	7.685	00.00	00.00
2009	10.268	32.621	52.084	00.00	00.00
2010	0.513	35.684	0.861	00.00	00.00
2011	3.808	2.102	1.082	00.00	00.00
2012	1.466	2.810	3.184	00.00	00.00
2013	5.244	0.319	0.690	00.00	00.00
2014	0.055	1.397	0.027	00.00	00.00
2015	0.002	0.042	0.102	00.00	00.00
2016	2.326	0.000	0.058	00.00	00.00
2017	0.004	0.697	1.358	00.00	00.00
Aver.	6.468	26.585	51.047	00.00	00.00

(d) Capacity utilization of the system

Tables 3.5 a, b, c, d, e and f show the capacity utilization for each planning year and also their average value for all the cases. Load factor practically remains the same irrespective of level of carbon tax imposed. The capacity factor increases with respect to the

base case for carbon tax 10 \$/ton, 50 \$/ton but it decreases with respect to base case for carbon tax 100 \$/ton, 200 \$/ton.

Table 3.5a: Annual system parameter with price elasticity –0.1

Year	Base Case			With carbon tax 10 \$/ton			With carbon tax 50 \$/ton		
	Cap. Fct. (%)	Load Fct. (%)	Unserved Energy. (MWh)	Cap. Fct. (%)	Load Fct. (%)	Unserved Energy. (MWh)	Cap. Fct. (%)	Load Fct. (%)	Unserved Energy. (MWh)
2003	50.22	66.54	17.712	50.38	66.54	42.442	50.13	66.54	236.910
2004	50.62	66.84	14.032	50.72	66.84	45.028	49.81	66.84	23.703
2005	50.58	67.15	36.370	50.63	67.15	83.204	50.67	67.15	7.533
2006	50.42	66.95	2.788	50.41	66.95	7.494	50.81	66.95	25.330
2007	50.72	67.05	3.101	50.67	67.05	13.825	51.15	67.05	19.662
2008	50.93	67.15	25.691	50.85	67.15	3.005	51.40	67.15	1.841
2009	50.45	67.32	10.268	50.71	67.32	5.113	51.50	67.32	5.161
2010	50.77	67.45	0.513	51.02	67.45	0.744	51.60	67.45	4.548
2011	50.98	67.56	3.808	51.13	67.56	5.947	51.60	67.56	16.956
2012	50.91	67.66	1.466	51.33	67.66	0.307	51.65	67.66	2.038
2013	51.06	67.76	5.244	51.42	67.76	8.827	51.59	67.76	0.152
2014	51.23	67.86	0.055	51.23	67.86	0.018	51.56	67.86	1.378
2015	51.19	67.86	0.002	51.43	67.86	0.003	51.76	67.86	0.020
2016	51.15	67.86	2.326	51.07	67.86	3.122	51.37	67.86	0.000
2017	51.14	67.96	0.004	50.90	67.96	0.011	51.30	67.96	1.111
Aver.	50.90	67.51	6.468	50.99	67.51	10.663	51.30	67.51	15.696

Table 3.5b: Annual system parameter with price elasticity –0.1

Year	Base Case			With carbon tax 100 \$/ton			With carbon tax 200 \$/ton		
	Cap. Fct. (%)	Load Fct. (%)	Unserved Energy. (MWh)	Cap. Fct. (%)	Load Fct. (%)	Unserved Energy. (MWh)	Cap. Fct. (%)	Load Fct. (%)	Unserved Energy. (MWh)
2003	50.22	66.54	17.712	48.44	66.54	6.884	45.98	66.54	0.567
2004	50.62	66.84	14.032	48.55	66.84	2.471	45.72	66.84	0.014
2005	50.58	67.15	36.370	48.81	67.15	0.439	46.09	67.15	0.017
2006	50.42	66.95	2.788	48.68	66.95	0.028	46.05	66.95	0,000
2007	50.72	67.05	3.101	49.00	67.05	0.035	46.67	67.05	0,000
2008	50.93	67.15	25.691	49.65	67.15	0.262	47.37	67.15	0.018
2009	50.45	67.32	10.268	51.18	67.32	0.573	48.30	67.32	0.000
2010	50.77	67.45	0.513	51.55	67.45	1.014	48.92	67.45	0.006
2011	50.98	67.56	3.808	51.40	67.56	0.564	50.80	67.56	0.006
2012	50.91	67.66	1.466	51.67	67.66	12.528	51.58	67.66	0.074
2013	51.06	67.76	5.244	51.46	67.76	1.791	52.13	67.76	0.093
2014	51.23	67.86	0.055	51.59	67.86	1.791	51.88	67.86	1.593
2015	51.19	67.86	0.002	51.65	67.86	0.011	52.25	67.86	0.025
2016	51.15	67.86	2.326	51.38	67.86	0.081	51.88	67.86	3.690
2017	51.14	67.96	0.004	51.14	67.96	0.000	51.81	67.96	0.016
Aver.	50.90	67.51	6.468	50.70	67.51	1.630	49.81	67.51	0.520

Table 3.5c: Annual system parameter with price elasticity –0.2

Year	Base Case			With carbon tax 10 $/ton			With carbon tax 50 $/ton		
	Cap. Fct. (%)	Load Fct. (%)	Unserved Energy. (MWh).	Cap. Fct. (%)	Load Fct. (%)	Unserved Energy. (MWh)	Cap. Fct. (%)	Load Fct. (%)	Unserved Energy. (MWh)
2003	50.22	66.54	17.712	50.36	66.54	103.871	49.73	66.54	462.398
2004	50.62	66.84	14.032	50.67	66.84	33.616	49.30	66.84	43.619
2005	50.58	67.15	36.370	51.05	67.15	244.765	50.55	67.15	340.769
2006	50.42	66.95	2.788	50.77	66.95	8.050	50.67	66.95	157.191
2007	50.72	67.05	3.101	50.97	67.05	32.745	50.95	67.05	40.200
2008	50.93	67.15	25.691	50.69	67.15	5.375	51.11	67.15	7.685
2009	50.45	67.32	10.268	50.70	67.32	6.974	51.32	67.32	52.084
2010	50.77	67.45	0.513	50.93	67.45	1.776	51.70	67.45	0.861
2011	50.98	67.56	3.808	51.05	67.56	17.853	52.13	67.56	1.082
2012	50.91	67.66	1.466	51.23	67.66	1.102	52.33	67.66	3.184
2013	51.06	67.76	5.244	51.13	67.76	0.005	52.32	67.76	0.690
2014	51.23	67.86	0.055	51.21	67.86	0.051	52.29	67.86	0.027
2015	51.19	67.86	0.002	51.37	67.86	0.001	52.52	67.86	0.102
2016	51.15	67.86	2.326	51.23	67.86	13.833	52.31	67.86	0.058
2017	51.14	67.96	0.004	51.01	67.96	0.032	52.07	67.96	1.358
Aver.	50.90	67.51	6.468	51.01	67.51	22.822	51.65	67.51	51.047

Table 3.5d: Annual system parameter with price elasticity –0.2

Year	Base Case			With carbon tax 100 $/ton			With carbon tax 200 $/ton		
	Cap. Fct. (%)	Load Fct. (%)	Unserved Energy. (MWh)	Cap. Fct. (%)	Load Fct. (%)	Unserved Energy. (MWh)	Cap. Fct. (%)	Load Fct. (%)	Unserved Energy. (MWh)
2003	50.22	66.54	17.712	47.06	66.54	3.626	42.08	66.54	0.001
2004	50.62	66.84	14.032	47.03	66.84	0.223	41.59	66.84	0.000
2005	50.58	67.15	36.370	47.35	67.15	0.535	42.05	67.15	0.000
2006	50.42	66.95	2.788	47.27	66.95	0.009	42.10	66.95	0.000
2007	50.72	67.05	3.101	47.63	67.05	0.003	42.77	67.05	0.000
2008	50.93	67.15	25.691	48.32	67.15	0.109	43.53	67.15	0.000
2009	50.45	67.32	10.268	49.25	67.32	0.011	44.50	67.32	0.000
2010	50.77	67.45	0.513	49.86	67.45	0.017	45.13	67.45	0.000
2011	50.98	67.56	3.808	51.34	67.56	0.009	45.98	67.56	0.000
2012	50.91	67.66	1.466	52.18	67.66	0.302	46.76	67.66	0.000
2013	51.06	67.76	5.244	51.92	67.76	0.052	47.89	67.76	0.000
2014	51.23	67.86	0.055	52.08	67.86	0.820	48.09	67.86	0.000
2015	51.19	67.86	0.002	52.31	67.86	0.026	48.09	67.86	0.000
2016	51.15	67.86	2.326	51.80	67.86	1.688	47.78	67.86	0.000
2017	51.14	67.96	0.004	51.77	67.96	0.007	48.62	67.86	0.000
Aver.	50.90	67.51	6.468	50.33	67.51	0.448	50.34	67.96	0.000

Table 3.5e: Annual system parameter with price elasticity –0.5

Year	Base Case			With carbon tax 10 $/ton			With carbon tax 50 $/ton		
	Cap. Fct. (%)	Load Fct. (%)	Unserved Energy. (MWh)	Cap. Fct. (%)	Load Fct. (%)	Unserved Energy. (MWh)	Cap. Fct. (%)	Load Fct. (%)	Unserved Energy. (MWh)
2003	50.22	66.54	17.712	50.24	66.54	295.524	49.73	66.54	462.398
2004	50.62	66.84	14.032	50.45	66.84	79.947	49.30	66.84	43.619
2005	50.58	67.15	36.370	50.74	67.15	13.369	50.55	67.15	340.769
2006	50.42	66.95	2.788	50.87	66.95	92.055	50.67	66.95	157.191
2007	50.72	67.05	3.101	50.97	67.05	4.449	50.95	67.05	40.200
2008	50.93	67.15	25.691	50.99	67.15	11.175	51.11	67.15	7.685
2009	50.45	67.32	10.268	50.90	67.32	32.621	51.32	67.32	52.084
2010	50.77	67.45	0.513	50.02	67.45	35.684	51.70	67.45	0.861
2011	50.98	67.56	3.808	51.22	67.56	2.102	52.13	67.56	1.082
2012	50.91	67.66	1.466	51.46	67.66	2.810	52.33	67.66	3.184
2013	51.06	67.76	5.244	51.24	67.76	0.319	52.32	67.76	0.690
2014	51.23	67.86	0.055	51.22	67.86	1.397	52.29	67.86	0.027
2015	51.19	67.86	0.002	51.43	67.86	0.042	52.52	67.86	0.102
2016	51.15	67.86	2.326	51.19	67.86	0.000	52.31	67.86	0.058
2017	51.14	67.96	0.004	51.11	67.96	0.697	52.07	67.96	1.358
Aver.	50.90	67.51	6.468	51.07	67.51	26.585	51.65	67.51	51.047

Table 3.5f: Annual system parameter with price elasticity –0.5

Year	Base Case			With carbon tax 100 $/ton			With carbon tax 200 $/ton		
	Cap. Fct. (%)	Load Fct. (%)	Unserved Energy. (MWh)	Cap. Fct. (%)	Load Fct. (%)	Unserved Energy. (MWh)	Cap. Fct. (%)	Load Fct. (%)	Unserved Energy. (MWh)
2003	50.22	66.54	17.712	00.00	00.00	00.00	00.00	00.00	00.00
2004	50.62	66.84	14.032	00.00	00.00	00.00	00.00	00.00	00.00
2005	50.58	67.15	36.370	00.00	00.00	00.00	00.00	00.00	00.00
2006	50.42	66.95	2.788	00.00	00.00	00.00	00.00	00.00	00.00
2007	50.72	67.05	3.101	00.00	00.00	00.00	00.00	00.00	00.00
2008	50.93	67.15	25.691	00.00	00.00	00.00	00.00	00.00	00.00
2009	50.45	67.32	10.268	00.00	00.00	00.00	00.00	00.00	00.00
2010	50.77	67.45	0.513	00.00	00.00	00.00	00.00	00.00	00.00
2011	50.98	67.56	3.808	00.00	00.00	00.00	00.00	00.00	00.00
2012	50.91	67.66	1.466	00.00	00.00	00.00	00.00	00.00	00.00
2013	51.06	67.76	5.244	00.00	00.00	00.00	00.00	00.00	00.00
2014	51.23	67.86	0.055	00.00	00.00	00.00	00.00	00.00	00.00
2015	51.19	67.86	0.002	00.00	00.00	00.00	00.00	00.00	00.00
2016	51.15	67.86	2.326	00.00	00.00	00.00	00.00	00.00	00.00
2017	51.14	67.96	0.004	00.00	00.00	00.00	00.00	00.00	00.00
Aver.	50.90	67.51	6.468	00.00	00.00	00.00	00.00	00.00	00.00

3.3.2 Cost and pricing implications

(a) Electricity prices

Electricity prices for all the considered cases are given in Table 3.6. It can be observed that the electricity price is the highest for carbon tax 200 $/ton when the price elasticity is – 0.1. The table also shows that the electricity price increases for higher value of carbon tax at the same price elasticity but electricity price decreases for higher price elasticity at the same carbon tax.

Table 3.6: Comparison of AIC at different carbon tax and price elasticity With base case AIC 3.0 US cents/KWh

Price Elasticity Constant	Carbon Tax ($/ton)	Average Incremental Cost (AIC) US cents/KWh
-0.1	10	3.41
	50	4.48
	100	5.35
	200	6.25
-0.2	10	3.37
	50	4.29
	100	4.71
	200	4.66
-0.5	10	3.31
	50	3.77
	100	0.00
	200	0.00

(b) Expansion cost during the planning horizon

Tables 3.7 a, b and c show the comparison of discounted expansion cost for all the cases in the planning horizon at the base year of 1998. The total expansion cost increased with respect to base case. The total expansion cost also increases with the increase in the level of carbon tax but it decreases with the increase in the level of price elasticity. The capital cost and fixed O&M cost decrease with increase in carbon tax and price elasticity. There is a significant amount of increase in fuel & variable cost due to introduction of carbon tax, but it shows reverse trend with increase in price elasticity

Table 3.7a: Expansion cost during planning horizon with Price elasticity = –0.1

Expansion costs during planning horizon (M$)	Generation expansion planning				
	Base case	With Carbon tax ($/ton)			
		10	50	100	200
Capital cost (1)	13592.42	13038.	11372.1	10375.8	8164.7
Fixed O&M (2)	6944.22	6827.3	6470.0	6258.9	5781.3
Fuel & variable (3)	26919.09	32466.0	49651.6	65205.2	49651.6
Sub total (1+2+3)	47455.73	52332	67493.9	81837.2	63579.0

Table 3.7b: Expansion cost during planning horizon with Price elasticity = –0.2

Expansion costs during planning horizon (M$)	Generation expansion planning				
	Base case	With Carbon tax ($/ton)			
		10	50	100	200
Capital cost (1)	13592.42	12619.7	9860.8	8078.5	4393.3
Fixed O&M (2)	6944.22	6733.7	6137.2	5757.1	4935.4
Fuel & variable(3)	26919.09	31792.2	46294.6	56734.2	62591.4
Sub total (1+2+3)	47455.73	51145.6	62292.8	70569.7	71920.1

Table 3.7c: Expansion cost during planning horizon with Price elasticity = –0.5

Expansion costs during planning horizon (M$)	Generation expansion planning				
	Base case	With Carbon tax ($/ton)			
		10	50	100	200
Capital cost (1)	13592.42	11666.2	5984.9	00.0	00.0
Fixed O&M (2)	6944.22	6521.3	5278.5	00.0	00.0
Fuel &variable (3)	26919.09	30184.9	37682.5	00.0	00.0
Sub total (1+2+3)	47455.73	48372.4	48946.1	00.0	00.0

3.3.3 Sensitivity Analysis with Change in demand (MW)

Tables 3.8 a, b, and c show comparison of demands for all the cases in the planning horizon. By changing the amount of carbon tax and price elasticity, the total demand falls down sharply with the increase in carbon tax and price elasticity. Thus it can be concluded that increasing the levels of carbon tax and price elasticity reduce the power demand and hence decrease the GHG emissions.

Table 3.8a: Demands at base case & different Ctax and P.E. –0.1

YEAR	Base Case	Ctax 10$/ton	Ctax 50$/ton	Ctax 100$/ton	Ctax 200$/tonl
	MW	MW	MW	MW	MW
2003	33800.00	33334.62	32038.33	30599.87	27489.99
2004	36169.00	35670.94	34283.93	32688.33	29416.64
2005	38613.00	38081.31	36600.51	34897.23	31404.40
2006	41223.00	40655.40	39074.45	37256.00	33527.20
2007	44009.00	43403.05	41715.30	39773.96	35793.10
2008	46835.00	46190.09	44393.97	42327.97	38091.50
2009	49843.00	49156.64	47245.23	45046.51	40537.90
2010	53043.00	53312.07	50279.35	47939.46	43141.40
2011	56451.00	55673.77	53508.83	51018.66	45912.30
2012	60077.77	59249.76	56945.85	54295.68	48861.40
2013	63935.00	63054.70	60602.74	57782.40	51999.10
2014	68040.00	67103.70	64493.87	61492.34	55337.73
2015	72405.00	71408.06	68631.34	65437.35	58886.96
2016	77055.00	75994.02	73038.95	69639.34	62669.75
2017	82000.00	80870.93	77726.21	74108.92	66691.61

Table 3.8b: Demands at base case & different Ctax and P.E. –0.2

YEAR	Base Case	Ctax 10$/ton	Ctax 50$/ton	Ctax 100$/ton	Ctax 200$/ton
	MW	MW	MW	MW	MW
2003	33800.00	32944.80	30491.40	27782.57	21519.89
2004	36169.00	35253.85	32628.59	29729.82	23028.10
2005	38613.00	37636.00	34833.35	31738.71	24584.14
2006	41223.00	40179.97	37184.92	33884.10	26245.88
2007	44009.00	42895.52	39701.15	36174.06	28019.67
2008	46835.00	45667.61	42250.56	38496.94	29818.94
2009	49843.00	48581.92	44964.13	40969.43	31734.09
2010	53043.00	51701.90	47850.92	43599.73	33771.46
2011	56451.00	55022.72	50925.30	46401.01	35941.25
2012	60077.77	58556.99	54196.30	49381.47	38249.88
2013	63935.00	62317.40	57876.72	52552.63	40706.39
2014	68040.00	66318.52	61379.89	55926.81	43319.75
2015	72405.00	70573.03	65317.58	59340.55	46098.87
2016	77055.00	75105.41	69512.42	63336.88	49059.43
2017	82000.00	79925.35	73973.37	67401.51	52207.81

Table 3.8c: Demands at base case & different Ctax and P.E. –0.5

YEAR	Base Case	Ctax 10$/ton	Ctax 50$/ton	Ctax 100$/ton	Ctax 200$/tonl
	MW	MW	MW	MW	MW
2003	33800.00	31920.70	26330.27	0.00	0.00
2004	36169.00	34157.99	28175.68	0.00	0.00
2005	38613.00	36466.09	30079.57	0.00	0.00
2006	41223.00	38930.98	32112.78	0.00	0.00
2007	44009.00	41562.17	34283.02	0.00	0.00
2008	46835.00	44230.96	36484.53	0.00	0.00
2009	49843.00	47070.99	38827.68	0.00	0.00
2010	53043.00	50093.78	41320.58	0.00	0.00
2011	56451.00	53312.31	43975.41	0.00	0.00
2012	60077.77	56736.69	46799.79	0.00	0.00
2013	63935.00	60380.18	49805.40	0.00	0.00

2014	68040.00	64256.94	53003.25	0.00	0.00
2015	72405.00	68379.25	56403.60	0.00	0.00
2016	77055.00	72770.71	60025.89	0.00	0.00
2017	82000.00	77440.76	63877.20	0.00	0.00

3.3.4 Environmental implications

Tables 3.9 a, b, c, d, e, f, g, h and i show the CO_2, SO_2 and NOx emission for all the considered cases in planning horizon. It can be observed that the introduction of carbon tax reduces GHG (only CO_2 considered in this study) and other pollutant emission for all price elasticity. It can also observe that as we go for higher carbon tax and price elasticity the percentage reduction of GHG increases because

- The demand reduces and so generation reduces according to demand.
- When imposition of carbon tax, power plants uses low carbon content fuel in spite of high carbon content fuel as they used earlier.
- The power producers try to adopt new technologies, which reduces the GHG emission at same level of generation.

In the case of NOx and SO_2 it can be observed that the introduction of carbon tax reduces the emission of the above gases, at higher rate of carbon tax reduction is more, i.e., as the level of carbon tax goes higher the % reduction also increases. Price elasticity has also very significant effect on the emission of NOx and SO_2 gases which are also called local pollutants. At higher price elasticity constant, the % reduction of NOx and SO_2 is more.

Table 3.9a: CO_2 (Gg) production with different Ctax and price elasticity –0.1

Year		2003	2007	2012	2017
Base case	Production	117615.7	160698.4	241255.2	347213.3
Ctax 10$/ton	Production	114543.0	155797.8	222292.6	340162.8
	% Reduction	2.6	3.1	7.8	2.0
Ctax 50$/ton	Production	97199.2	123894.2	178475.4	284148.1
	% Reduction	17.3	22.9	26.0	18.2
Ctax 100$/ton	Production	90019.2	111714.7	162403.7	262278.5
	% Reduction	23.4	30.4	32.7	24.5
Ctax 200$/ton	Production	78848.8	97313.4	129845.6	218145.4
	% Reduction	32.9	39.4	46.2	37.2

Table 3.9b CO_2 (Gg) production with different Ctax and price elasticity –0.2

Year		2003	2007	2012	2017
Base case	Production	117615.7	160698.4	241255.2	347213.3
Ctax 10$/ton	Production	113295.0	152849.2	220094.3	334579.0
	% Reduction	3.6	4.9	8.7	3.6
Ctax 50$/ton	Production	93126.2	118399.9	162024.0	261689.9
	% Reduction	20.8	26.3	32.8	24.6
Ctax 100$/ton	Production	80945.8	100093.2	133233.6	222175.5
	% Reduction	31.2	37.7	44.7	36.0
Ctax 200$/ton	Production	59509.6	72202.6	92947.8	131465.1
	% Reduction	49.4	55.1	61.5	62.1

Table 3.9c: CO_2 (Gg) production with different Ctax and price elasticity –0.5

Year		2003	2007	2012	2017
Base case	Production	117615.7	160698.4	241255.2	347213.3
Ctax 10$/ton	Production	109984.9	147240.9	212939.0	317798.6
	% Reduction	6.5	8.4	11.7	8.5
Ctax 50$/ton	Production	83885.3	105976.7	127986.3	201824.4
	% Reduction	28.6	34.1	46.9	41.8
Ctax 100$/ton	Production	00.0	00.0	00.0	00.0
	% Reduction	00.0	00.0	00.0	00.0
Ctax 200$/tonl	Production	00.0	00.0	00.0	00.0
	% Reduction	00.0	00.0	00.0	00.0

Table 3.9d: NOx (Mkg) production with different Ctax and price elasticity –0.1

Year		2003	2007	2012	2017
Base case	Production	354.1	458.4	648.3	911.7
Ctax 10$/ton	Production	344.7	445.1	610.5	892.8
	% Reduction	2.65	2.90	5.83	2.07
Ctax 50$/ton	Production	293.2	366.7	509.9	769.8
	% Reduction	17.19	20.00	21.35	15.56
Ctax 100$/ton	Production	273.0	334.2	468.5	714.0
	% Reduction	22.90	27.09	27.73	21.68
Ctax 200$/ton	Production	240.3	292.2	387.8	606.6
	% Reduction	32.13	36.25	40.18	33.46

Table 3.9e: NOx (Mkg) production with different Ctax and price elasticity –0.2

Year		2003	2007	2012	2017
Base case	Production	354.1	458.4	648.3	911.7
Ctax 10$/ton	Production	340.9	437.9	603.9	880.7
	% Reduction	3.69	4.47	6.84	3.39
Ctax 50$/ton	Production	280.7	350.6	469.8	714.9
	% Reduction	20.70	23.49	27.52	21.58
Ctax 100$/ton	Production	245.9	299.6	396.9	606.4
	% Reduction	30.52	34.64	38.76	33.48
Ctax 200$/ton	Production	182.7	217.4	279.3	393.0
	% Reduction	48.37	52.57	56.92	56.88

Table 3.9f: NOx (Mkg) production with different Ctax and price elasticity –0.5

Year		2003	2007	2012	2017
Base case	Production	354.1	458.4	648.3	911.7
Ctax 10$/ton	Production	331.1	422.8	584.2	814.7
	% Reduction	6.49	7.76	9.88	10.63
Ctax 50$/ton	Production	251.6	311.3	379.6	569.1
	% Reduction	28.94	32.08	41.44	37.57
Ctax 100$/ton	Production	00.0	00.0	00.0	00.0
	% Reduction	00.0	00.0	00.0	00.0
Ctax 200$/ton	Production	00.0	00.0	00.0	00.0
	% Reduction	00.0	00.0	00.0	00.0

Table 3.9g: SO_2 (Mg) production with different Ctax and price elasticity –0.1

Year		2003	2007	2012	2017
Base case	Production	575154.6	870513.6	1374577.4	1940022.5
Ctax 10$/ton	Production	557049.0	834885.6	1189356.2	1897950.8
	% Reduction	3.14	4.09	13.47	2.16
Ctax 50$/ton	Production	381081.6	494406.6	731623.4	1328706.7
	% Reduction	33.74	43.20	46.77	31.51
Ctax 100$/ ton	Production	338672.9	409703.8	633584.5	1196486.9
	% Reduction	41.11	52.93	53.90	38.32
Ctax 200$/ ton	Production	310085.1	371689.7	437736.8	942049.3
	% Reduction	45.08	57.30	68.15	51.44

Table 3.9h: SO_2 (Mg) production with different Ctax and price elasticity –0.2

Year		2003	2007	2012	2017
Base case	Production	575154.6	870513.6	1374577.4	1940022.5
Ctax 10$/ton	Production	556146.7	818176.0	1188011.7	1865084.6
	% Reduction	3.30	6.01	13.57	3.86
Ctax 50$/ ton	Production	389133.7	502382.4	635364.9	1197121.3
	% Reduction	32.34	42.28	53.77	38.29
Ctax 100$/ ton	Production	331915.5	400507.5	460375.9	962071.9
	% Reduction	42.29	53.99	66.50	50.40
Ctax 200$/ ton	Production	293256.6	350575.0	364685.1	424157.0
	% Reduction	49.01	59.72	73.46	78.13

Table 3.9i: SO_2 (Mg) production with different Ctax and price elasticity –0.5

Year		2003	2007	2012	2017
Base case	Production	575154.6	870513.6	1374577.4	1940022.5
Ctax 10$/ton	Production	553468.4	799385.3	1168189.0	1757526.2
	% Reduction	3.77	8.17	15.01	9.40
Ctax 50$/ ton	Production	429649.8	550881.3	493573.7	847096.8
	% Reduction	25.29	36.71	64.09	56.33
Ctax 100$/ ton	Production	0.00	0.00	0.00	0.00
	% Reduction	100.00	100.00	100.00	100.00
Ctax 200$/ ton	Production	0.00	0.00	0.00	0.00
	% Reduction	100.00	100.00	100.00	100.00

3.4 CONCLUSIONS

The work reported in this chapter has studied the impact of introducing carbon tax in the generation expansion planning on the cost and emission of GHG and other pollutants. Studies were carried out for different price elasticity constants -0.1, -0.2 and –0.5 for the NREB system of India. On the basis of the results obtained for various cases and sensitivity analyses carried out, following conclusions are.

With the introduction of carbon tax, capacity mix of hydro plants increases with decrease in capacity mix of coal plants. Total installed capacity also reduces with the introduction of carbon tax. All candidate hydro power plants got selected during the planning horizon but some thermal candidate plants did not get selected in some cases. Average unserved energy increases for carbon tax (10 $/ton, 50 $/ton) but it reduces for higher carbon tax (100 $/ton, 200 $/ton). For higher price elasticity values, the average unserved energy increases for carbon tax (10 $/ton, 50 $/ton) but it decreases very sharply for carbon tax (100 $/ton, 200 $/ton). Thus, average capacity utilization increases with the imposition of carbon tax.

- Introduction of carbon tax reduces CO_2 emission along with the local pollutants SO_2 and NOx emission in all the cases .It also reduces the capital cost and fixed O&M cost but increases the fuel & variable costs. The total generation expansion planning cost increases as we go for higher carbon tax but it reduces for the higher price elasticity values.
- Introduction of carbon tax increases the electricity price. It was seen that the price of electricity increases for higher carbon tax as compared to lower rate of carbon tax.
- All the available hydro plants get selected in each of the considered cases as these have less O&M cost and zero fuel cost. With the imposition of carbon tax, the number of units selected got decreased which were using coal 4 and coal 6 as the fuel. The number of units of nuclear and CCGT remained the same at all carbon tax and price elasticity values. For different price elasticity cases, a sharp decrease in number of coal 4 and coal 6 plants at higher level of carbon tax, as we increase the price elasticity.

- Total installed capacity decreases with the increase of carbon tax. It also shows that the plant capacity decreases sharply with higher value of carbon tax. The share of hydro plant increases but share of thermal power decreases, as we increase the level of carbon tax.
- Introduction of carbon tax decreases the total demand in all cases. It also shows that demand reduces very sharply at higher price elasticity as compared to lower price elasticity values. Demand reduced to zero when both price elasticity and carbon tax were very high (carbon tax 100$/ton & 200$/ton at price elasticity –0.5).

CHAPTER 4

IDENTICIFICATION AND RANKING OF BARRIERS IN PROMOTION OF CLEAN AND ENERGY EFFICIENT POWER GENERATION TECHNOLOGIES

4.1 INTRODUCTION

The electricity generation in India is expected to increase at a higher rate than the global average. In India, power generation is predominantly based on fossil fuels. Thus, the shares of thermal generation are also likely to increase for a given expected growth of electricity generation. Consequently, it is expected that GHG emissions will increase considerably. Thus, the subject of reduction of GHG emissions in power sector has gained immense importance. There are number of technical options for reducing GHG and other harmful emissions from the power sector, which can be divided as clean technologies and energy-efficient technologies. A large number of studies have shown that a significant proportion of clean and energy-efficient (CEE) technologies those have significant impact on Asian energy use and GHG emissions, are cost effective and not adopted [4]. The study presented in chapter-2 has shown that some of the efficient supply side and demand side options will be selected in future least cost expansion plan to achieve a desired CO_2 reduction target. However, some of these technologies such as IGCC, PFBC etc. are not yet adopted in Indian power sector due to set of technical, financial and other barriers. For a given number of policy instruments, the choice of appropriate instrument is very important. It may not be possible for a single instrument to overcome a particular barrier. A combination of various policies may be adopted. It is important to study whether there are other characteristics, other than cost, those are more important in adopting clean and energy efficient technologies in power sector.

The overall objective of this study is to exploit, what are the important characteristics in adopting CEE technologies or to identify the major barriers in the adoption of these technologies and rank them using a software package known as AHP & Expert Choice. In this study, the barrier for implementing each of cost effective and environmental friendly options has been ranked. In order to rank the barriers a list of attributes or criteria has been defined. Different actors have different perceptions about the barriers and the effect of barriers. A survey opinion from a selected group of people working in power area has been obtained and the identification and raking of barriers have been obtained for few select CEE technologies with the help of the AHP package.

4.2 METHODOLOGY

The main aim of the study reported in this chapter is to identify and rank the barriers in adoption of clean and energy-efficient (CEE) technologies. Only four CEE technologies have been considered for identification of barriers [1]. These are IGCC, PFBC, BIGCC and Solar. Wind, Hydro and CCGT are also CEE technologies but these were not considered in this analysis because they are very well adopted in the Indian power system. The figure 4.1 shows a simple AHP model example for identification and ranking of barriers. In this model the four CEE alternative (IGCC, PFBC, BIGCC and Solar) and barriers (technical, informational, economic etc.) are taken into account. One of the major strengths of AHP is the use of pairwise comparisons to derive accurate ratio scale priorities, instead of using traditional approaches of 'assigning' weights. This process compares the relative importance, performance or likelihood of two elements with respect to other element. A Judgment is made as to which is more important and by how much. This process shows the overall solution by synthesizing (combining) all global priorities for each alternative and then presents the results in both graphical and numerical form.

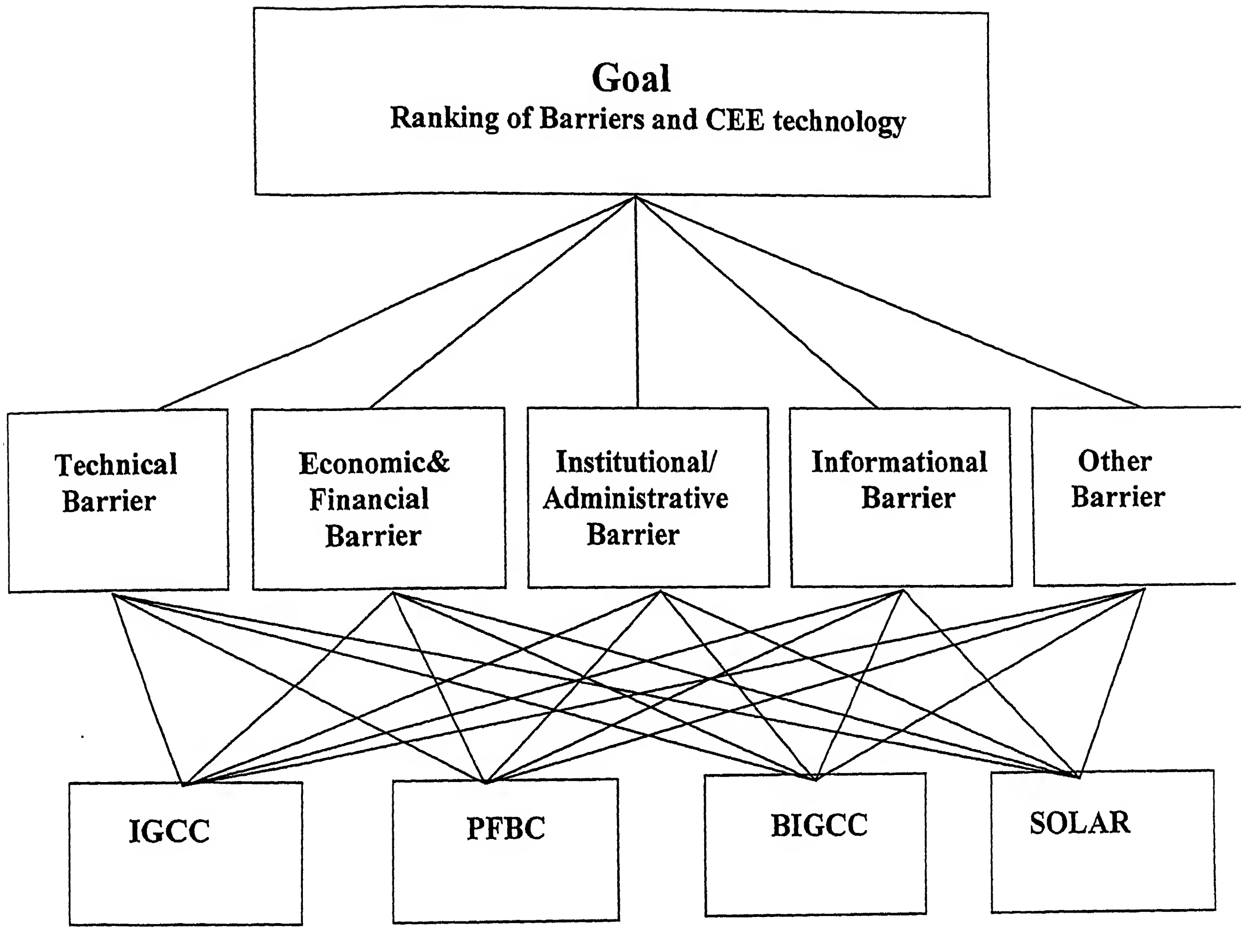


Fig. 4.1 AHP Model Example

4.2.1 Principles of forming a hierarchy

- A hierarchy starts from more general and less controllable at the top to more specific and controllable at the bottom.
- Components at the same level must have equal interest or importance.
- Components at the lower level are capable of explaining characteristics of the components in the higher level they belong to.
- A hierarchy should be rich enough to represent your problem, but simple enough to reflect sensitivity.

Priority Principle

- AHP captures priorities from paired comparison judgments of the elements of the decision respect to each of their parent criteria
- Paired comparison judgments can be arranged in a matrix form.
- Priorities are derived from the matrix as its principle eigenvector, which defines a ratio scale. It also allows for the measurement of inconsistency. An inconsistency ratio is calculated for each set of judgments. Inconsistency follows the transitive property. For example, if one states $A > B$ and $B > C$, and also states that $C > A$, the statement is defined as inconsistent [12].

Theoretical Information about inconsistency

The inconsistency index, not ratio, is calculated for each barrier (and its sub barriers), and multiplied by the priority of the barrier, and summed over the entire model. A similar calculation is done for the inconsistency index for random judgments [12]. The overall Inconsistency Ratio is the ratio of the two weighted sums.

It has been shown that for any matrix, small perturbation in the entries imply similar perturbation in the eigenvalues; thus the eigenvalue problem for the inconsistent case is

- Inconsistency case

  $A\mathrm{W} = \lambda_{\max}\mathrm{w}$

- Consistency case

  $AW = nW$

Where A is the matrix of pairwise comparisons, $\lambda_{\max}$ will be close to n (actually greater than or equal to n) and the other lambdas will be close to zero. The estimates of the weights for the activities can be found by normalizing the eigenvector corresponding to the largest eigenvalue in the above matrix equation.

The closer $\lambda_{\max}$ will be close to n, the more consistent your judgments. Thus the difference, $\lambda_{\max} - n$, can be used as a measure of inconsistency (this difference will be zero for perfect consistency). Instead of using this difference directly, consistency index (CI) defined as:

$$\mathrm{CI} = (\lambda_{\max} - n)/(n-1)$$

- **The informational barriers include**

➢ Low exposure to information sources (Lack of technical and financial information and of demonstrated track record for many CEE technologies).

➢ Low level of awareness (Even in all relevant information is available to the users, individual users may, in some cases; be unable to make proper use of information. This may be so because of user's lack of cognitive skills, the absorption and interpretation of factual information and use of that information in decision-making).

- **The market barriers include**

➢ Lack of energy efficient product.

- **The technical barriers may be of the form of**

➢ Lack of technical capability for adoption.

➢ Quality attributes of CEE technologies and supply.

- **The barrier Consumer behavior includes**

➢ Perceived riskiness and attitude towards CEE technologies.

➢ Customs and social norms.

- **Others barriers**

These include individual barriers, political barriers and others. For example, individual barriers include consumer preference and social biases. Political issues can also be a crucial constraint for implementation of mitigation option.

4.2.3 Ranking of Barriers

It is proposed to develop a hierarchical system to rank the respective barriers for the selected options (which are analyzed to be environment friendly and cost effective), based on different criteria. The AHP (Analytic Hierarchical Process) Model is a suitable tool for this

because AHP combines deductive approach of solving problem into one, integrated logical framework.

The hierarchy system has been formulated with objectives, criteria and the different options (the barriers). Interviewing different participants and experts in the sector would collect information. The interview has performed to find information and their opinions regarding the constraints and barrier against implementing the feasible alternative options in power sector. This information is then used to rank the barriers for each of the alternative options.

The software package supporting the AHP, called Expert choice has been used for the analysis.

The different steps involved in AHP are:

- State the problem.
- Identify the criteria that influence the behavior of the problem.
- Structure the hierarchy of the criteria and alternatives. The criteria or factors, based on which the alternative barriers would be ranked would have to be defined.

4.3 FORMULATION OF PROBLEM

Objective

The overall objective is to rank the barriers to adoption of CEE technologies in power sector. Different participants have different perceptions about the barriers and the effect of barriers. Based upon different opinion of different participants, the overall priorities of the barriers and also CEE technologies have been obtained.

Participants:

Total seven participants were selected for gathering the expert opinions. Participants A, B and C were the faculty members at I I T Kanpur working in the power area and also in the environmental projects. Other four participants include three senior Ph.D. students (participants D, E and F) and one M.Tech student (participants G) working in the power area at I I T Kanpur.

Criteria:

In order to rank the barriers one must define certain attributes or criteria through which it will be ranked. These attributes are based on the characteristics of barrier. Barriers obstruct in adopting a technology and ranges from minor obstruction to major ones. Some barriers are

easy to understand while others are not. To understand the criteria better, it is important to identify the barrier first. The following section discusses some of the important attributes of the barrier.

- Monetary cost to remove

Cost of removing the barriers varies with the type and nature of barriers. Cost in the form of subsidy can be used to remove the barrier related to high initial cost and the high cost of capital. Similarly, barriers of information and awareness could be overcome through financing in the Internet facilities, TV/local paper advertisements and public campaign programs.

- Level of efforts to Create Awareness

To overcome the barrier, awareness about the efficient technology plays a major role. Once the user is aware of the existence of technology and nature of technology, and then adopting such technology becomes relatively easy. Therefore, it is very important to create awareness among the users.

- Impact on Adoption

Different barriers have different level of impact on the adoption of efficient options. Removing a particular barrier could result in a higher level of introduction of efficient options than some other barriers. This feature implicitly recognizes the importance of barriers. Barrier that is easy to overcome may have less impact in terms of adoption of options. On the other hand, barrier that is difficult to remove may have larger impact in adoptions.

- Life of barrier

Each barrier has its own life, i.e., the time it takes to cease. Without any external intervention, some barriers tend to last long compared to other barriers. This means that barriers can be assessed from its life. Normally, barriers with shorter life would be preferable to longer ones.

Actors are requested to look critically into the criteria described above, because this is core part of ranking using AHP. It is very important to understand each of these factors to give a rational judgement while comparing one barrier over another.

4.4 RESULTS AND DISCUSSIONS

Table 4.1(a) shows a sample survey sheet used to get the feedback of experts in ranking of the barriers. Different barriers and their respective sub-barriers in the selection of clean and energy technology (CEE) have shown in the table. It shows that, there are eight global barriers (availability of technology, cost, efficiency, infrastructure, pollution, availability of R&D, skilled manpower and suitability of fuel) with respect to the goal ranking of barriers in the selection of CEE in power generation technologies. With respect to each global barrier, local barriers are defined. The AHP output of this table is given in table 4.1(b). Numerical values in this table against each global barrier denote the relative impact of the barrier assigned in the selection of CEE in power generation technologies. Numerical values in the table against each local barrier denote the relative impact of local barrier assigned on the global barrier.

Table 4.2 a, b, c. d, e, f and g show the comparison of ranking of different barriers in the selection of clean and energy efficient (CEE) technologies corresponding to each of the participants response. In this study, there are four alternatives of CEE (IGCC, BIGCC, PFBC and Solar) technologies. Different participants choose different rating options against each barrier, from the survey sheet. Based on the rating options of different participants, different ranking were assigned by the AHP software.

`To evaluate the overall ranking of different CEE technology, geometric mean method has been used.

➢ **Technology options selected**

Table 4.3 shows that the individual ranking of alternate CEE technologies. Higher-ranking value indicates lower amount of barriers assigned to the technology.

a: BARRIERS IN ADOPTION OF CLEAN TECHNOLOGIES FOR POWER GENERATION

SURVEY SHEET

Barriers	Sub Barriers	IGCC	PFBC	BIGCC	Solar
Availability of Technology	Unavailability of efficient technology locally				
	Reliability of alternate technology				
	Lack of technical capability for adoption				
	Quality attributes of CEE technologies and supply				
	Higher perceived risk of the more efficient technology				
Cost	Higher capital cost				
	Lack of capital investment and financing instruments				
	Low profit				
	Low energy price				
Efficiency	Low efficiency				
	Lack of energy efficient product market				
Infrastruct-ure	Lack of infrastructure				
	Lack of legal and regulatory framework				
	Multiplicity of authorities				
	Low level of awareness				
	Low exposure to information sources				
	High transaction costs				
Pollution	Emission of high GHG gases				
	Local pollutants (SO_2, NOx)				
R & D	Inadequate R&D in the area of CEE technologies				
	Lack of technical standards and institutions				
Skilled man power	Lack of trained personnel				
	Lack of cognitive skills				
Suitability of Fuel	Unavailability of fuels				
	Higher cost of alternate fuel				

Notes: (1) You are requested to provide your opinion on the rating of barriers for each of the four clean generation technologies.

(2) The rating options can be one of the following against each entry.

Rating options

Very Large (1)
High (2)
Average (3)
Low (4)
Very Low (5)

Treeview

Goal: ranking of barriers

- **availability of technology (G:.131)**
  - **unavailability of efficient technologies (G:.029)**
  - **reliability of alternate technologies (G:.032)**
  - **lack of technical capability for adoption (G:.027)**
  - **quality attributes of CEE technologies and supply (G:.023)**
  - **higher perceived risk of the more efficient technologies (G:.020)**
- **cost (G:.307)**
  - **higher capital cost (G:.173)**
  - **lack of investment capital and financing instruments (G:.050)**
  - **low profit (G:.040)**
  - **low energy price (G:.043)**
- **efficiency (G:.088)**
  - **low efficiency (G:.043)**
  - **lack of energy efficient products (G:.045)**
- **infrastructure (G:.039)**
  - **lack of infrasucture (G:.009)**
  - **lack of legal and regulatory framework (G:.007)**
  - **mutiplicity of authorities (G:.006)**
  - **low level of awareness (G:.006)**
  - **low exposure to information sources (G:.005)**
  - **high transaction costs (G:.006)**
- **pollution (G:.277)**
  - **emission of high green house gases (G:.231)**
  - **environmental hazards (G:.046)**
- **R & D available (G:.059)**
  - **unadequate R & D in the area of CEE technologies (G:.051)**
  - **lack of technical standards and institutions for supporting the standards (G:.008)**
- **Skilled manpower (G:.042)**
  - **lack of trained personnel or technical or manegerial expertise (G:.026)**
  - **lack of cognitive skills (G:.016)**
- **suitability of fuel (G:.057)**
  - **unavailability of fuels (G:.038)**

higher cost of alternate fuel (G:.020)

Alternatives

availability of technology	.131
cost	.307
efficiency	.088
infrastructure	.039
pollution	.277
R & D available	.059
Skilled manpower	.042
suitability of fuel	.057

Table 4.2a: AHP output for participant-A

Ideal mode		RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	Total	availability of technology unavailability of efficient technologies (G:.029)	availability of technology reliability of alternate technologies (G:.032)	availability of technology lack of technical capability for adoption (G:.027)	availability of technology quality attributes of CEE technologies and supply (G:.023)	availability of technology higher perceived risk of the more efficient technologies (G:.020)
✓ BIGCC	.650	HIGH	LOW	LOW	AVERAGE	HIGH
✓ Solar	.720	HIGH	HIGH	HIGH	HIGH	MODERATE
✓ IGCC	.673	AVERAGE	HIGH	HIGH	LOW	VERY HIGH
✓ PFBC	.816	HIGH	LOW	LOW	HIGH	LOW

Ideal mode	RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	cost higher capital cost (G:.173)	cost lack of investment capital and financing instruments (G:.050)	cost low profit (G:.040)	cost low energy price (G:.043)	efficiency low efficiency (G:.043)
✓ BIGCC	HIGH	HIGH	VERY HIGH	LOW	AVERAGE
✓ Solar	HIGH	HIGH	HIGH	LOW	HIGH
✓ IGCC	HIGH	LOW	HIGH	LOW	AVERAGE
✓ PFBC	AVERAGE	HIGH	VERY HIGH	LOW	LOW

Ideal mode	RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	efficiency lack of energy efficient products (G: 045)	infrastructure lack of infrasructure (G: 009)	infrastructure lack of legal and regulatory framework (G: 007)	infrastructure multiplicity of authorities (G: 006)	infrastructure low level of awareness (G: 006)
☑ [illegible]	AVERAGE	HIGH	AVERAGE	LOW	LOW
☑ [illegible]	AVERAGE	HIGH	HIGH	LOW	LOW
☑ [illegible]	HIGH	LOW	HIGH	LOW	AVERAGE
☑ [illegible]	LOW	AVERAGE	LOW	HIGH	HIGH

Ideal mode	RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	infrastructure low exposure to information sources (G: 005)	infrastructure high transaction costs (G: 006)	pollution emission of high green house gases (G: 231)	pollution environmental hazards (G: 046)	R & D available unadequate R & D in the area of CEE technologies (G: 051)
☑ [illegible]	LOW	AVERAGE	HIGH	VERY HIGH	HIGH
☑ [illegible]	HIGH	AVERAGE	LOW	HIGH	VERY HIGH
☑ [illegible]	HIGH	HIGH	VERY HIGH	AVERAGE	AVERAGE
☑ [illegible]	HIGH	AVERAGE	LOW	LOW	AVERAGE

Ideal mode	RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	R & D available lack of technical standards and institutions for supporting the standards (G: 008)	Skilled manpower lack of trained personnel or technical or managerial expertise (G: 026)	Skilled manpower lack of cognitive skills (G: 016)	suitability of fuel unavailability of fuels (G: 038)	suitability of fuel higher cost of alternate fuel (G: 020)
☑ [illegible]	HIGH	VERY HIGH	AVERAGE	AVERAGE	HIGH
☑ [illegible]	AVERAGE	HIGH	HIGH	AVERAGE	AVERAGE
☑ [illegible]	HIGH	LOW	HIGH	LOW	VERY HIGH
☑ [illegible]	LOW	VERY HIGH	HIGH	LOW	HIGH

Table 4.2b: AHP output for participant-B

Ideal mode		RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	Total	availability of technology unavailability of efficient technologies (L:.224)	availability of technology reliability of alternate technologies (L:.244)	availability of technology lack of technical capability for adoption (L:.203)	availability of technology quality attributes of CEE technologies and supply (L:.175)	availability of technology higher perceived risk of the more efficient technologies (L:.154)
[illegible]	.779	AVERAGE	HIGH	LOW	HIGH	MODERATE
[illegible]	.768	LOW	HIGH	HIGH	HIGH	MODERATE
[illegible]	.663	HIGH	GREAT	HIGH	AVERAGE	MODERATE
[illegible]	.713	HIGH	GREAT	HIGH	AVERAGE	MODERATE

Ideal mode	RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	cost higher capital cost (L:.566)	cost lack of investment capital and financing instruments (L:.164)	cost low profit (L:.131)	cost low energy price (L:.139)	efficiency low efficiency (L:.490)
BIGCC	AVERAGE	LOW	AVERAGE	AVERAGE	AVERAGE
[illegible]	VERY HIGH	HIGH	LOW	HIGH	LOW
NGCC	HIGH	HIGH	HIGH	HIGH	HIGH
PFBC	HIGH	AVERAGE	AVERAGE	HIGH	HIGH

Ideal mode	RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	efficiency lack of energy efficient products (L:510)	infrastructure lack of infrasucture (L:226)	infrastructure lack of legal and regulatory framework (L:178)	infrastructure multiplicity of authorities (L:146)	infrastructure low level of awareness (L:165)
☑ [illegible]	AVERAGE	AVERAGE	AVERAGE	HIGH	HIGH
☑ [illegible]	AVERAGE	HIGH	AVERAGE	HIGH	HIGH
☑ [illegible]	AVERAGE	LOW	LOW	HIGH	LOW
☑ [illegible]	AVERAGE	LOW	LOW	HIGH	AVERAGE

Ideal mode	RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	infrastructure low exposure to information sources (L:123)	infrastructure high transaction costs (L:163)	pollution emission of high green house gases (L:833)	pollution environmental hazards (L:167)	R & D available unadequate R & D in the area of CEE technologies (L:857)
☑ [illegible]	HIGH	AVERAGE	AVERAGE	AVERAGE	AVERAGE
☑ [illegible]	AVERAGE	AVERAGE	LOW	LOW	AVERAGE
☑ [illegible]	HIGH	HIGH	AVERAGE	AVERAGE	HIGH
☑ [illegible]	HIGH	HIGH	AVERAGE	LOW	HIGH

Ideal mode	RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	R & D available lack of technical standards and institutions for supporting the standards (L:.143)	Skilled manpower lack of trained personnel or technical or manegerial expertise (L:.617)	Skilled manpower lack of cognitive skills (L:.383)	suitability of fuel unavailability of fuels (L:.659)	suitability of fuel higher cost of alternate fuel (L:.341)
☑ [redacted]	AVERAGE	AVERAGE	AVERAGE	LOW	AVERAGE
☑ [redacted]	AVERAGE	AVERAGE	LOW	LOW	LOW
☑ [redacted]	HIGH	VERY HIGH	AVERAGE	HIGH	HIGH
☑ [redacted]	HIGH	HIGH	AVERAGE	LOW	AVERAGE

Table 4.2c: AHP output for participant-C

Ideal mode		RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	Total	availability of technology unavailability of efficient technologies (L:.224)	availability of technology reliability of alternate technologies (L:.244)	availability of technology lack of technical capability for adoption (L:.203)	availability of technology quality attributes of CEE technologies and supply (L:.175)	availability of technology higher perceived risk of the more efficient technologies (L:.154)
[illegible]	.877	LOWEST	HIGH	AVERAGE	LOW	LOW
[illegible]	.798	LOWEST	LOW	AVERAGE	LOW	LOW
[illegible]	.774	HIGH	HIGH	HIGH	LOW	HIGH
[illegible]	.783	HIGH	HIGH	AVERAGE	LOW	HIGH

Ideal mode	RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	cost higher capital cost (L:.566)	cost lack of investment capital and financing instruments (L:.164)	cost low profit (L:.131)	cost low energy price (L:.139)	efficiency low efficiency (L:.490)
☑ [illegible]	AVERAGE	LOW	LOW	AVERAGE	LOW
☑ [illegible]	VERY HIGH	LOW	HIGH	AVERAGE	LOW
☑ [illegible]	HIGH	LOW	LOW	LOW	LOW
☑ [illegible]	HIGH	LOW	LOW	LOW	LOW

Ideal mode	RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	efficiency lack of energy efficient products (L:.510)	infrastructure lack of infrasucture (L:.226)	infrastructure lack of legal and regulatory framework (L:.178)	infrastructure mutiplicity of authorities (L:.146)	infrastructure low level of awareness (L:.166)
☑ [illegible]	LOW	LOW	LOW	LOW	LOW
☑ [illegible]	LOW	LOW	LOW	LOW	LOW
☑ [illegible]	HIGH	HIGH	HIGH	HIGH	AVERAGE
☑ [illegible]	HIGH	HIGH	HIGH	HIGH	AVERAGE

Ideal mode	RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	infrastructure low exposure to information sources (L:.123)	infrastructure high transaction costs (L:.163)	pollution emission of high green house gases (L:.833)	pollution environmental hazards (L:.167)	R & D available unadequate R & D in the area of CEE technologies (L:.857)
☑ [illegible]	LOW	LOW	LOW	AVERAGE	AVERAGE
☑ [illegible]	LOW	LOW	LOW	AVERAGE	AVERAGE
☑ [illegible]	AVERAGE	HIGH	LOW	AVERAGE	VERY HIGH
☑ [illegible]	AVERAGE	HIGH	LOW	AVERAGE	HIGH

Ideal mode	RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	R & D available lack of technical standards and institutions for supporting the standards (L:.143)	Skilled manpower lack of trained personnel or technical or manegerial expertise (L:.617)	Skilled manpower lack of cognitive skills (L:.383)	suitability of fuel unavailability of fuels (L:.659)	suitability of fuel higher cost of alternate fuel (L:.341)
☑ [illegible]	LOW	LOW	AVERAGE	LOW	LOW
☑ [illegible]	LOW	LOW	AVERAGE	LOW	LOW
☑ [illegible]	HIGH	HIGH	HIGH	LOW	LOW
☑ [illegible]	HIGH	HIGH	HIGH	LOW	LOW

Table 4.2d: AHP output for participant-D

Ideal mode		RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	Total	availability of technology unavailability of efficient technologies (L:.224)	availability of technology reliability of alternate technologies (L:.244)	availability of technology lack of technical capability for adoption (L:.203)	availability of technology quality attributes of CEE technologies and supply (L:.175)	availability of technology higher perceived risk of the more efficient technologies (L:.154)
☑ [redacted]	.723	AVERAGE	HIGH	LOW	LOW	MODERATE
☑ [redacted]	.820	LOW	HIGH	LOW	HIGH	MODERATE
☑ [redacted]	.707	AVERAGE	HIGH	HIGH	HIGH	MODERATE
☑ [redacted]	.740	AVERAGE	HIGH	AVERAGE	HIGH	MODERATE

Ideal mode / Alternative	RATINGS cost higher capital cost (L.:566)	RATINGS cost lack of investment capital and financing instruments (L.:164)	RATINGS cost low profit (L.:131)	RATINGS cost low energy price (L.:139)	RATINGS efficiency low efficiency (L.:490)
☑ [illegible]	AVERAGE	AVERAGE	AVERAGE	HIGH	HIGH
☑ [illegible]	VERY HIGH	LOW	VERY HIGH	LOW	HIGH
☑ [illegible]	HIGH	HIGH	HIGH	AVERAGE	LOW
☑ [illegible]	HIGH	HIGH	HIGH	AVERAGE	LOW

Ideal mode / Alternative	RATINGS efficiency lack of energy efficient products (L.:510)	RATINGS infrastructure lack of infrasucture (L.:226)	RATINGS infrastructure lack of legal and regulatory framework (L.:178)	RATINGS infrastructure mutiplicity of authorities (L.:146)	RATINGS infrastructure low level of awareness (L.:165)
☑ [illegible]	HIGH	LOW	AVERAGE	HIGH	LOW
☑ [illegible]	LOW	AVERAGE	AVERAGE	HIGH	LOW
☑ [illegible]	AVERAGE	HIGH	AVERAGE	HIGH	AVERAGE
☑ [illegible]	AVERAGE	VERY HIGH	AVERAGE	HIGH	HIGH

Ideal mode	RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	infrastructure low exposure to information sources (L:.123)	infrastructure high transaction costs (L:.163)	pollution emission of high green house gases (L:.833)	pollution environmental hazards (L:.167)	R & D available unadequate R & D in the area of CEE technologies (L:.857)
☑ [illegible]	LOW	AVERAGE	HIGH	HIGH	LOW
☑ [illegible]	LOW	AVERAGE	LOW	LOW	LOW
☑ [illegible]	AVERAGE	HIGH	AVERAGE	AVERAGE	AVERAGE
☑ [illegible]	HIGH	HIGH	LOW	LOW	HIGH

Ideal mode	RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	R & D available lack of technical standards and institutions for supporting the standards (L:.143)	Skilled manpower lack of trained personnel or technical or manegerial expertise (L:.617)	Skilled manpower lack of cognitive skills (L:.383)	suitability of fuel unavailability of fuels (L:.659)	suitability of fuel higher cost of alternate fuel (L:.341)
☑ [illegible]	LOW	AVERAGE	AVERAGE	LOW	LOW
☑ [illegible]	LOW	LOW	LOW	LOW	LOW
☑ [illegible]	HIGH	AVERAGE	HIGH	AVERAGE	AVERAGE
☑ [illegible]	HIGH	AVERAGE	HIGH	HIGH	HIGH

Table 4.2e: AHP output for participant-E

Ideal mode		RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	Total	availability of technology unavailability of efficient technologies (L: .224)	availability of technology reliability of alternate technologies (L: .244)	availability of technology lack of technical capability for adoption (L: .203)	availability of technology quality attributes of CEE technologies and supply (L: .175)	availability of technology higher perceived risk of the more efficient technologies (L: .154)
☑ [illegible]	.745	HIGH	HIGH	AVERAGE	HIGH	LOW
☑ [illegible]	.732	HIGH	HIGH	LOW	HIGH	LOW
☑ [illegible]	.688	HIGH	HIGH	AVERAGE	HIGH	LOW
☑ [illegible]	.714	HIGH	HIGH	AVERAGE	HIGH	LOW

Ideal mode	RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	cost higher capital cost (L:566)	cost lack of investment capital and financing instruments (L:164)	cost low profit (L:131)	cost low energy price (L:139)	efficiency low efficiency (L:490)
☑ [illegible]	HIGH	HIGH	LOW	VERY HIGH	LOW
☑ [illegible]	VERY HIGH	HIGH	LOW	HIGH	HIGH
☑ [illegible]	HIGH	HIGH	LOW	VERY HIGH	HIGH
☑ [illegible]	VERY HIGH	HIGH	LOW	VERY HIGH	LOW

Ideal mode	RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	efficiency lack of energy efficient products (L:510)	infrastructure lack of infrasucture (L:226)	infrastructure lack of legal and regulatory framework (L:178)	infrastructure mutiplicity of authorities (L:146)	infrastructure low level of awareness (L:165)
☑ [illegible]	HIGH	HIGH	AVERAGE	HIGH	HIGH
☑ [illegible]	HIGH	HIGH	AVERAGE	AVERAGE	LOW
☑ [illegible]	HIGH	VERY HIGH	AVERAGE	HIGH	HIGH
☑ [illegible]	HIGH	HIGH	AVERAGE	HIGH	HIGH

Ideal mode	RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	infrastructure low exposure to information sources (L:.123)	infrastructure high transaction costs (L:.163)	pollution emission of high green house gases (L:.833)	pollution environmental hazards (L:.167)	R & D available unadequate R & D in the area of CEE technologies (L:.857)
☑ [illegible]	HIGH	HIGH	LOW	LOW	VERY HIGH
☑ [illegible]	LOW	HIGH	LOW	LOW	AVERAGE
☑ [illegible]	HIGH	HIGH	AVERAGE	LOW	VERY HIGH
☑ [illegible]	HIGH	HIGH	LOW	LOW	VERY HIGH

Ideal mode	RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	R & D available lack of technical standards and institutions for supporting the standards (L:.143)	Skilled manpower lack of trained personnel or technical or manegerial expertise (L:.617)	Skilled manpower lack of cognitive skills (L:.383)	suitability of fuel unavailability of fuels (L:.659)	suitability of fuel higher cost of alternate fuel (L:.341)
☑ [illegible]	HIGH	VERY HIGH	HIGH	LOW	HIGH
☑ [illegible]	HIGH	AVERAGE	AVERAGE	HIGH	LOW
☑ [illegible]	HIGH	VERY HIGH	HIGH	LOW	AVERAGE
☑ [illegible]	HIGH	HIGH	HIGH	AVERAGE	HIGH

Table 4.2f: AHP output for participant-F

Ideal mode Alternative	Total	RATINGS availability of technology unavailability of efficient technologies (G:.029)	RATINGS availability of technology reliability of alternate technologies (G:.032)	RATINGS availability of technology lack of technical capability for adoption (G:.027)	RATINGS availability of technology quality attributes of CEE technologies and supply (G:.023)	RATINGS availability of technology higher perceived risk of the more efficient technologies (G:.020)
✓ [illegible]	.794	LOW	HIGH	LOW	HIGH	MODERATE
✓ [illegible]	.816	LOWEST	HIGH	LOWEST	HIGH	MODERATE
✓ [illegible]	.688	AVERAGE	MODERATE	LOW	AVERAGE	LOW
✓ [illegible]	.698	AVERAGE	HIGH	LOW	HIGH	MODERATE

Ideal mode Alternative	RATINGS cost higher capital cost (G:.173)	RATINGS cost lack of investment capital and financing instruments (G:.050)	RATINGS cost low profit (G:.040)	RATINGS cost low energy price (G:.043)	RATINGS efficiency low efficiency (G:.043)
✓ [illegible]	AVERAGE	LOW	AVERAGE	LOW	AVERAGE
✓ [illegible]	VERY HIGH	HIGH	LOW	LOW	HIGH
✓ [illegible]	HIGH	HIGH	VERY HIGH	AVERAGE	LOW
✓ [illegible]	HIGH	AVERAGE	VERY HIGH	VERY HIGH	LOW

Ideal mode Alternative	RATINGS efficiency lack of energy efficient products (G:.045)	RATINGS infrastructure lack of infrasucture (G:.009)	RATINGS infrastructure lack of legal and regulatory framework (G:.007)	RATINGS infrastructure mutiplicity of authorities (G:.006)	RATINGS infrastructure low level of awareness (G:.006)
☑ [illegible]	AVERAGE	AVERAGE	AVERAGE	HIGH	LOW
☑ [illegible]	LOW	LOW	AVERAGE	HIGH	LOW
☑ [illegible]	HIGH	VERY HIGH	LOW	HIGH	HIGH
☑ [illegible]	HIGH	VERY HIGH	LOW	HIGH	HIGH

Ideal mode Alternative	RATINGS infrastructure low exposure to information sources (G:.005)	RATINGS infrastructure high transaction costs (G:.006)	RATINGS pollution emission of high green house gases (G:.231)	RATINGS pollution environmental hazards (G:.046)	RATINGS R & D available unadequate R & D in the area of CEE technologies (G:.051)
☑ [illegible]	LOW	AVERAGE	HIGH	HIGH	LOW
☑ [illegible]	LOW	LOW	LOW	LOW	LOW
☑ [illegible]	HIGH	HIGH	AVERAGE	AVERAGE	HIGH
☑ [illegible]	HIGH	HIGH	AVERAGE	AVERAGE	HIGH

Ideal mode	RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	R & D available lack of technical standards and institutions for supporting the standards (G:.008)	Skilled manpower lack of trained personnel or technical or manegerial expertise (G:.026)	Skilled manpower lack of cognitive skills (G:.016)	suitability of fuel unavailability of fuels (G:.038)	suitability of fuel higher cost of alternate fuel (G:.020)
[illegible]	LOW	LOW	LOW	LOW	LOW
[illegible]	LOW	AVERAGE	LOW	LOW	VERY HIGH
[illegible]	HIGH	VERY HIGH	HIGH	LOW	HIGH
[illegible]	HIGH	HIGH	HIGH	LOW	HIGH

Table 4.2g: AHP output for participant-G

Ideal mode		RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	Total	availability of technology unavailability of efficient technologies (G:.029)	availability of technology reliability of alternate technologies (G:.032)	availability of technology lack of technical capability for adoption (G:.027)	availability of technology quality attributes of CEE technologies and supply (G:.023)	availability of technology higher perceived risk of the more efficient technologies (G:.020)
[illegible]	.686	AVERAGE	MODERATE	AVERAGE	AVERAGE	MODERATE
[illegible]	.765	LOW	HIGH	LOW	LOW	LOW
[illegible]	.715	HIGH	HIGH	HIGH	LOW	HIGH
[illegible]	.706	HIGH	HIGH	HIGH	LOW	HIGH

Ideal mode	RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	cost higher capital cost (G:.173)	cost lack of investment capital and financing instruments (G:.050)	cost low profit (G:.040)	cost low energy price (G:.043)	efficiency low efficiency (G:.043)
[illegible]	AVERAGE	HIGH	AVERAGE	AVERAGE	AVERAGE
[illegible]	VERY HIGH	HIGH	AVERAGE	AVERAGE	HIGH
[illegible]	HIGH	HIGH	AVERAGE	AVERAGE	LOW
[illegible]	HIGH	HIGH	AVERAGE	VERY HIGH	LOW

Ideal mode	RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	efficiency lack of energy efficient products (G:.045)	infrastructure lack of infrasucture (G:.009)	infrastructure lack of legal and regulatory framework (G:.007)	infrastructure mutiplicity of authorities (G:.006)	infrastructure low level of awareness (G:.006)
☑ [redacted]	HIGH	AVERAGE	AVERAGE	HIGH	LOW
☑ [redacted]	HIGH	LOW	AVERAGE	HIGH	LOW
☑ [redacted]	HIGH	HIGH	HIGH	HIGH	HIGH
☑ [redacted]	HIGH	HIGH	HIGH	HIGH	HIGH

Ideal mode	RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	infrastructure low exposure to information sources (G:.005)	infrastructure high transaction costs (G:.006)	pollution emission of high green house gases (G:.231)	pollution environmental hazards (G:.046)	R & D available unadequate R & D in the area of CEE technologies (G:.051)
☑ [redacted]	LOW	AVERAGE	VERY HIGH	AVERAGE	AVERAGE
☑ [redacted]	LOW	LOW	LOW	LOW	LOW
☑ [redacted]	HIGH	HIGH	LOW	LOW	HIGH
☑ [redacted]	HIGH	HIGH	LOW	LOW	HIGH

Ideal mode	RATINGS	RATINGS	RATINGS	RATINGS	RATINGS
Alternative	R & D available lack of technical standards and institutions for supporting the standards (G:.008)	Skilled manpower lack of trained personnel or technical or manegerial expertise (G:.026)	Skilled manpower lack of cognitive skills (G:.016)	suitability of fuel unavailability of fuels (G:.038)	suitability of fuel higher cost of alternate fuel (G:.020)
☑ [illegible]	LOW	LOW	AVERAGE	LOW	AVERAGE
☑ [illegible]	AVERAGE	LOW	LOW	LOW	LOW
☑ [illegible]	HIGH	HIGH	HIGH	HIGH	HIGH
☑ [illegible]	HIGH	HIGH	HIGH	HIGH	HIGH

Table 4.3: Individual ranking of CEE technologies

Participants	Ranking of alternatives			
	IGCC	PFBC	BIGCC	Solar
A	0.774	0.783	0.877	0.798
B	0.688	0.714	0.745	0.732
C	0.663	0.713	0.779	0.768
D	0.688	0.698	0.794	0.816
E	0.673	0.816	0.650	0.720
F	0.707	0.740	0.723	0.820
G	0.715	0.706	0.686	0.765

After applying Geometric Mean Method of the results from the table 4.3 the overall ranking of CEE technologies are listed in Table 4.4. This shows that adoption of BIGCC technology will involve least barrier and IGCC technology will involve maximum barrier. The ranking of barriers from the survey results of the experts are summarized in Table 4.5

Table 4.4: Overall ranking of CEE technologies

Alternative CEE technologies	Ranking of barriers
IGCC	0.231
PFBC	0.244
Solar	0.256
BIGCC	0.249
Total	1.000

Table 4.5: Ranking of Barriers

CEE Technology	Barriers
IGCC	1. Unavailability of efficient technology locally 2. Reliability of alternate technology 3. Lack of capital investment and financing instrument 4. Lack of technical capability for adoption 5. Low efficiency 6. Lack of energy efficient product market
PFBC	1. Unavailability of efficient technology locally 2. Reliability of alternate technology 3. Lack of capital investment and financing instrument 4. Low energy price
BIGCC	1. Reliability of alternate technology 2. Quality attributes of CEE technologies and supply 3. Low energy price 4. Lack of trained personnel
Solar	1. Higher capital cost 2. Low efficiency 3. Lack of energy efficient product market 4. Low energy price

4.5 CONCLUSIONS

The work reported in this chapter has studied the impact of barriers in selection of CEE technology options in the generation expansion planning. Studies were carried out for both global barriers and local barriers. In this study, judgments about the relative importance of objectives (barriers) are made with respect to the parent node (global barriers) in the hierarchy (either the Goal or a global barrier). Judgments about relative preference of alternatives are made with respect to each covering objective (local barrier). Covering objectives are lowest level objectives (local barriers) against which all alternatives are judged. On the basis of the results obtained, following conclusion can be drawn.

➢ The clean and energy efficient technology selected in this study using the AHP software with minimum barrier in BIGCC technology and that with maximum barrier in the IGCC technology.

➢ In this study the inconsistency defined by AHP was 0.06, which is less than acceptable value of 0.1.

➢ Two most important barriers in the adoption of the four CEE technologies are.

1. For IGCC technology, the two most important include (Unavailability of efficient technology locally) and (Reliability of alternate technology).
2. For PFBC technology, the two most important include (Unavailability of efficient technology locally) and (Reliability of alternate technology).
3. For BIGCC technology, the two most important include (Reliability of alternate technology) and (Quality attributes of CEE technologies and supply)
4. For Solar technology, the two most important include (Higher capital cost) and (Low efficiency).

CHAPTER 5

CONCLUSION

Increased emission of greenhouse gases and other pollutants from power sector and its detrimental impacts on the global and local environment has made this aspect to be addressed in the utility planning. In this thesis, cost-effectiveness and environmental emission mitigating potential of clean and energy efficient (CEE) technologies and impact of imposition of carbon tax on fossil fuels proportionate to their carbon content on generation expansion planning has been studied and their impact on the power sector planning has been analyzed. The study has been carried out under the traditional resource planning (TRP) and integrated resource planning (IRP) perspectives on Northern Regional Electricity Board network of India. Adoption of any new CEE technology involves certain financial, technological and societal barriers. Identification and ranking of few CEE technologies have been carried out with the help of AHP/Expert choice software. The main findings of the study carried out in this thesis are given below.

The study carried out in chapter-2 with respect to effect of supply- and demand-side options for generation expansion planning reveal that all candidate hydro plants are fully selected due to their low capital cost, practically no operating cost and zero emissions. Solar plants are not selected in any of the cases due to their high capital cost whereas wind plants are fully selected in all the cases. Due to the high fuel cost of Coal6 plants, these are not selected in most of the cases. Average capacity utilization increases but average unserved energy decreases with increase in CO_2 emission reduction level. Total expansion cost increases with increase in emission reduction target. The CEE technologies selected in future expansion plan include IGCC, PFBC and BIGCC plants.

With the introduction of carbon tax, as presented in chapter-3 the hydro power plant capacity mix increases in each year with all level of carbon taxes. This is due to the fact that all candidate power plants, which got selected, were of hydro type. The selection of candidate thermal power plants having coal as a fuel decreases as level of carbon tax is increased. The hydrothermal mix is highest in year 2007 as all the candidate hydro plants got

selected in this year. The total generation (MWh) decreases as the level of carbon tax and price elasticity values are increased. The share of coal based power plants (in %) decreased as the higher carbon tax was imposed. The share of nuclear and hydro plants (in %) continuously increased every year because on imposition of carbon tax, all candidate nuclear and hydro power plants got selected. The average unserved energy increases for carbon tax values of 10 \$/ton, 50 \$/ton but for carbon tax 100 \$/ton, 200 \$/ton, it decreases. For higher price elasticity values, the average unserved energy increases for carbon tax of 10 \$/ton and 50 \$/ton but it decreases very sharply for carbon tax of 100 \$/ton and 200 \$/ton. The average capacity utilization increases with the imposition of carbon tax.

The clean and energy efficient technology selected in this study using the AHP software with minimum barrier in BIGCC technology and that with maximum barrier in the IGCC technology. Two most important barriers in the adoption of the four CEE technologies are.

(I) For IGCC technology, the two most important include (Unavailability of efficient technology locally) and (Reliability of alternate technology).

(II) For PFBC technology, the two most important include (Unavailability of efficient technology locally) and (Reliability of alternate technology).

(III) For BIGCC technology, the two most important include (Reliability of alternate technology) and (Quality attributes of CEE technologies and supply)

(IV) For Solar technology, the two most important include (Higher capital cost) and (Low efficiency).

As a consequence of the study carried out in this thesis, following areas of further research work have been identified:

1. While identifying the environmental emission mitigation potential in the planning studies, cost of societal benefits due to the emission reduction have not been considered in the model. The IRPA can be modified to include societal benefit also.

2. In some of the countries, energy tax has been introduced to mitigate the greenhouse gas emission. This aspect may also be studied on Indian power system networks.

3. Studies can be extended to other Regional Electricity Board Network in the country.

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Appendix A

CONSTRAINTS IN THE LEAST COST GENERATION PLANNING

The least cost optimization is subject to the following system constraints.

a) Demand constraints

This constraint states that the total power generation in each block of the planning horizon, from candidate and existing plants, will be more than or equal to the power demand during that period. It can be mathematically written as

$$\sum_{v=1}^{t}\sum_{j=1}^{J} U_{jpstv} \times (1 - M_{jpst}) + \sum_{v=-V}^{t}\sum_{k=1}^{K} U_{kpstv} \times (1 - M_{kpst}) \geq Q_{pst} \qquad \text{(A.1).}$$

for all p, s, t.

Where,

U_{jpstv}: Power generation from candidate plant j of vintage v in block p of season s in year t.

M_{jpst}: Transmission loss for transmitting power from candidate generating station j to load center in block p of season s in year t.

U_{kpstv}: Power generation from existing plant k of vintage v in block p of season s in year t.

M_{kpst}: Transmission loss for transmitting power from existing generating station k to load center in block p of season s in year t.

b) Reliability constraints

This constraint imposes the condition that the power demand from all the plants (the candidate and the existing plants of all the types) must be greater than or equal to the sum of the power demand by the consumers and the reserve margin.

$$\sum_{k=1}^{K}\sum_{v=-V}^{t} B_{kv} \times (1 - M_{kp^*st}) + \sum_{j=1}^{J}\sum_{v=1}^{t} Y_{jv} \times B_{jv} \times (1 - M_{jp^*st}) \geq Q_{p^*st}(1 + rm) \qquad \text{(A.2).}$$

for all t, s.

(P^* represents the peak block).

Where,

U_{kpstv}: Power generation form plant k of vintage v in block p of season s in year.

β_{jv}: Firm factor of hydro plant j of vintage v.

U_{jpstv}: Power generation from candidate plant j of vintage v in block p of season s in year t.

Q_{pst}: Power demand in block p of season s in year t.

d) Plant availability constraints

This constraint defines the maximum, available generation from each power plant depending on their availability factor.

$$U_{jpstv} \leq Y_{jv} \times a_{jv} \times B_{jv}$$

for all j, v, p, s, t.

and

$$U_{kpstv} \leq a_{jv} \times B_{kv}$$

for all k, v, p, s, t (A.4).

Where,

U_{jpstv}: Power generation from candidate plant j of vintage v in block p of season s in year t.

Y_{jv}: Number of power plants of type j installed in year v (An integer variable).

a_{jv}: Availability of candidate power plant j of vintage v.

B_{jv}: Maximum capacity of candidate power plant j of vintage v.

U_{kpstv}: Power generation from plant k of vintage v in block p of season s in year t.

a_{kv}: availability of existing or committed power plant k of vintage v.

B_{kv}: Maximum capacity of existing or committed power plant k of vintage v.

e) Annual energy constraints

This constraint defines the maximum energy, which can be generated from each plant considering their maintenance period.

$$\sum_{p=1}^{P}\sum_{s=1}^{S} U_{jpstv} \times \theta_{pst} \times N_{st} \leq \left(8760 - m_{jv}\right) \times B_{jv} \times Y_{jv}$$

for all j, v, t.

and

$$\sum_{p=1}^{P}\sum_{s=1}^{S} U_{kpstv} \times \theta_{pst} \times N_{st} \leq \left(8760 - m_{kv}\right) \times B_{kv}$$

for all k, v, t (A.5).

Where,

U_{jpstv}: Power generation from candidate plant j of vintage v in block p of season s in year t.

θ_{pst}: Width of block p of chronological load curve of season s of year t.

N_{st}: Number of days in season s of year t

m_{jv}: Schedule maintenance hours per year of candidate power plant j of vintage v.

B_{jv}: Maximum capacity of candidate power plant j of vintage v.

Y_{jv}: Number of power plants of type j installed in year v (An integer variable).

U_{kpstv}: Power generation from plant k of vintage v in block p of season s in year t.

m_{kv}: Schedule maintenance hours per year of existing or committed plant k of vintage v.

B_{kv}: Maximum capacity of existing or committed power plant k of vintage v.

f) Hydro energy availability constraints

This constraint defines the limit on total hydro energy generation available from each hydro plant, during each period.

$$\sum_{p=1}^{P}\left(U_{jpstv} \times \theta_{pst}\right) \times N_{st} \leq \pi_{jstv}$$

for all j, s, t, v (j=Hydro plants).

and

$$\sum_{p=1}^{P}\left(U_{kpstv} \times \theta_{pst}\right) \times N_{st} \leq \pi_{kstv}$$

for all k, s, t, v (k=Hydro plants) (A.6).

Where,

U_{jpstv} : Power generation from candidate plant j of vintage v in block p of season s in year t.

θ_{pst} : Width of block p of chronological load curve of season s of year t.

N_{st}: Number of days in season s of year t.

π_{jstv} : Hydro energy available at hydro plant j of vintage v, in season s, in year t.

U_{kpstv}: Power generation from plant k of vintage v in block p of season s in year t.

π_{kstv} : Hydro energy available at hydro plant k of vintage v, in season s, in year t.

g) Maximum potential capacity constraints

This constraint imposes the limit on the number of power plants of any type installed in any year.

$$\sum_{v=1}^{T} Y_{jv} \le \alpha_j$$

for all j (A.7).

where,

Y_{jv} : Number of power plants of type j installed in year v (An integer variable).

α_j: Maximum number of units of power plant type j.

h) Fuel or resource availability constraints

This constraint imposes the maximum limit on energy generation for each type computed from the availability of fuel resources

$$\sum_{t=1}^{T}\sum_{s=1}^{S}\sum_{p=1}^{P}\sum_{v=-V}^{t} Y_{kv} \times U_{kpstv} \times \theta_{pst} \times N_{st} + \sum_{t=1}^{T}\sum_{s=1}^{S}\sum_{p=1}^{P}\sum_{v=1}^{t} Y_{jv} \times U_{jpstv} \times \theta_{pst} \times N_{st} \le X_{j\max}$$

for all k, j k and j are some type of plants (A.8).

Where,

Y_{kv}: Number of power plants of type k installed in year v (An integer variable).

U_{kpstv} : Power generation from plant k of vintage v in block p of season s in year t.

θ_{pst} : Width of block p of chronological load curve of season s of year t.

N_{st} : Number of days in season s of year t.

Y_{jv}: Number of power plants of type j installed in year v (An integer variable).

U_{jpstv}: Power generation from candidate plant j of vintage v in block p of season s in year t.

$X_{j\,max}$: Maximum energy resource available for plant type j (computed based on the maximum fuel resource availability).

G) Calculation of emission constraints and heat rate

SO_2 and CO_2 emission factors are calculated by using following formula adopted by CEA.

CO_2 emission factor:

$$ef_{co_2}\left[\frac{Kg}{MWh}\right]=\left(44/_{12}\right)\times 10\times C_{con}\times P_{car}$$

SO_2 emission factor:

$$ef_{so_2}\left[\frac{Kg}{MWh}\right]=2\times 10\times C_{con}\times P_{sul}$$

NO_x emission factor is taken from IPCC document [20]

$$ef_{no_x}\left[\frac{Kg}{MWh}\right]=\frac{NO_x\times 0.4187\times H.R.}{10^5}$$

where,

ef: Emission factor (Kg/Kwh).

C_{con}: Specific coal consumption in Kg/Kwh.

P_{car}: Percentage of carbon in coal.

P_{sul}: Percentage of sulphur in coal.

Ef_{Nox}: Emission factor (Kg/Mwh).

H.R.: Heat rate in Kcal/Kwh.

NO_x: The NO_x emission expressed in Kg/TJ.

Plant efficiency (η) has been calculated from the heat rates as following.

$$\eta=\frac{860}{H.R.}\times 100\%$$

where,

H.R.= Heat rate of the plant at full load in kcal/kWh.

Appendix B

B-1: Existing thermal power plants

NAME	Fuel type	Fuel con.	Cal. Value (kBtu/ kg)	CO2 emis. (kg/ MWh)	SO2 emis. (kg/ MWh)	NOx emis. (kg/ MWh)	Capacity (MW)	Heat rate (kcal/ kwh)	Oper. cost (000'$/ MWh)	Annual maint. (Hours)	Fixed O&M (000'$/ MWmonth)
BADARPUR1	COAL	0.8	14.27	1144	8	5.14	85	3213	0.0012	864	2
BADARPUR2	COAL	0.8	14.27	1144	8	5.14	85	3213	0.0012	864	2
BADARPUR3	COAL	0.8	14.27	1144	8	5.14	85	3213	0.0012	864	2
BADARPURXT-1	COAL	0.7	14.27	1001	7	4.45	190	2781	0.0012	864	2
BADARPURXT-2	COAL	0.7	14.27	1001	7	2.78	190	2781	0.0012	864	2
IP-60	COAL	0.85	15.19	1277.83	8.5	5.82	54	3636	0.0012	864	2
IP-1	COAL	0.85	15.19	1277.83	8.5	5.82	56	3636	0.0012	864	2
IP-2	COAL	0.85	15.19	1277.83	8.5	5.82	56	3636	0.0012	864	2
IP-3	COAL	0.85	15.19	1277.83	8.5	5.82	56	3636	0.0012	864	2
RAJGHAT-2	COAL	0.82	17.65	1473.27	8.2	6.52	61	4075	0.0012	864	2
RAJGHAT-3	COAL	0.82	17.65	1473.27	8.2	6.52	60	4075	0.0012	864	2
GAS-DESU-1WH	GAS	0.221	41.74	504.43	0.37	1.59	45.5	1982	0.0008	1296	1.67
GAS-DESU-2WH	GAS	0.221	41.74	504.43	0.37	1.59	45.5	1982	0.0008	1296	1.67
GAS-DESU-3WH	GAS	0.221	41.74	504.43	0.37	1.59	45.5	1982	0.0008	1296	1.67
GAS-DESU-4WH	GAS	0.221	41.74	504.43	0.37	1.59	45.5	1982	0.0008	1296	1.67
GAS-DESU-5WH	GAS	0.221	41.74	504.43	0.37	1.59	45.5	1982	0.0008	1296	1.67
GAS-DESU-6WH	GAS	0.221	41.74	504.43	0.37	1.59	45.5	1982	0.0008	1296	1.67
FARIDABADXT1	COAL	0.9	17.88	1617	9	7.25	49	4530	0.0012	864	2
FARIDABADXT2	COAL	0.9	17.88	1617	9	7.25	49	4530	0.0012	864	2
FARIDABADXT3	COAL	0.9	17.88	1617	9	7.25	49	4530	0.0012	864	2
PANIPAT-1	COAL	0.9	15.34	1353	9	3.89	98	3887	0.0012	864	2
PANIPAT-2	COAL	0.9	15.34	1353	9	3.89	98	3887	0.0012	864	2
PANIPAT-3	COAL	0.9	15.34	1353	9	3.89	98	3887	0.0012	864	2
PANIPAT-4	COAL	0.9	15.34	1353	9	3.89	98	3887	0.0012	864	2
PANIPAT-5	COAL	0.85	15.34	1277.83	8.5	3.63	190	3630	0.0012	864	2
FARIDABADCCGT-A	GAS	0.221	41.74	504.43	0.37	1.59	139	1982	0.0008	1296	1.67
PAMPORE-1GT	OIL	0.3	42.66	935	6	2.42	25	3030	0.0008	1296	1.67
PAMPORE-2GT	OIL	0.3	42.66	935	6	2.42	25	3030	0.0008	1296	1.67
PAMPORE-3GT	OIL	0.3	42.66	935	6	2.42	25	3030	0.0008	1296	1.67
PAMPORE-4GT-II	OIL	0.3	42.66	935	6	2.42	25	3030	0.0008	1296	1.67
PAMPORE-5GT-II	OIL	0.3	42.66	935	6	2.42	25	3030	0.0008	1296	1.67
PAMPORE-6GT-II	OIL	0.3	42.66	935	6	2.42	25	3030	0.0008	1296	1.67
PAMPORE-7GT-II	OIL	0.3	42.66	935	6	2.42	25	3030	0.0008	1296	1.67
BHATINDAlehmoh1	COAL	0.75	15.82	1155	7.5	3.3	190	3303	0.0012	864	2
BHATINDAlehmoh2	COAL	0.75	15.82	1155	7.5	3.3	190	3303	0.0012	864	2
GNDTP-1	COAL	0.75	15.82	1155	7.5	3.34	98	3340	0.0012	864	2
GNDTP-2	COAL	0.75	15.46	1155	7.5	3.27	98	3265	0.0012	864	2
GNDTP-3	COAL	0.75	15.46	1155	7.5	3.27	98	3265	0.0012	864	2
GNDTP-4	COAL	0.75	15.46	1155	7.5	3.27	98	3265	0.0012	864	2
ROPAR-I/1	COAL	0.67	15.38	1031.8	6.7	2.87	190	2870	0.0012	864	2
ROPAR-I/2	COAL	0.67	15.38	1031.8	6.7	2.87	190	2870	0.0012	864	2
ROPAR-II/1	COAL	0.67	15.38	1031.8	6.7	2.87	190	2870	0.0012	864	2
ROPAR-II/2	COAL	0.67	15.38	1031.8	6.7	2.87	190	2870	0.0012	864	2
ROPAR-IIIXT-1	COAL	0.67	15.38	1031.8	6.7	2.87	190	2870	0.0012	864	2
ROPAR-IIIXT-2	COAL	0.67	15.38	1031.8	6.7	2.87	190	2870	0.0012	864	2
KOTA-1	COAL	0.7	16.27	1103.67	7	3.21	98	3207	0.0012	864	2
KOTA-2	COAL	0.7	16.27	1103.67	7	3.21	98	3207	0.0012	864	2
KOTAXT-3	COAL	0.64	16.27	1009.07	6.4	2.9	190	2899	0.0012	864	2
KOTAXT-4	COAL	0.64	16.27	1009.07	6.4	2.9	190	2899	0.0012	864	2
KOTAXT-5	COAL	0.64	16.27	1009.07	6.4	2.9	190	2899	0.0012	864	2
SURATGARHTPS-I 1	COAL	0.46	16.27	725.27	4.6	2.08	226	2084	0.0012	864	2
ANTAGAS-1	GAS	0.221	41.74	504.43	0.37	1.59	85	1982	0.0008	1296	1.67
ANTAGAS-2	GAS	0.221	41.74	504.43	0.37	1.59	85	1982	0.0008	1296	1.67
ANTAGAS-3	GAS	0.221	41.74	504.43	0.37	1.59	85	1982	0.0008	1296	1.67
ANTAGAS-4	GAS	0.221	41.74	504.43	0.37	1.59	145	1982	0.0008	1296	1.67
RAMGARHGAS	GAS	0.221	41.74	504.43	0.37	1.55	3	1942	0.0008	1296	1.67
RAMGARHGAS	GAS	0.221	41.74	504.43	0.37	1.55	35	1942	0.0008	1296	1.67
RAPP-1	NUCL	0.027	406350	0	0	0	90	3072	0.0015	864	2.7

RAPP-2	NUCL	0.027	406350	0	0	0	180	3072	0.0015	864	2.7
ANPARA'A'-1	COAL	0.75	16.08	1155	7.5	3.36	190	3357	0.0012	864	2
ANPARA'A'-2	COAL	0.75	16.08	1155	7.5	3.36	190	3357	0.0012	864	2
ANPARA'A'-3	COAL	0.75	16.08	1155	7.5	3.36	190	3357	0.0012	864	2
ANPARA'B'-1	COAL	0.6	16.08	924	6	2.64	460	2642	0.0012	864	2
ANPARA'B'-2	COAL	0.6	16.08	924	6	2.64	460	2642	0.0012	864	2
H'GANJB-1	COAL	2003	17.88	1796.67	10	8.06	36	5036	0.0012	864	2
H'GANJB-3	COAL	0.9	17.88	1617	9	7.25	54	4532	0.0012	864	2
H'GANJB-2	COAL	2003	17.88	1796.67	10	8.06	36	5036	0.0012	864	2
H'GANJB-4	COAL	0.9	17.88	1617	9	7.25	54	4532	0.0012	864	2
H'GANJC-1	COAL	0.9	17.88	1617	9	7.25	54	4532	0.0012	864	2
H'GANJC-2	COAL	0.9	17.88	1617	9	7.25	54	4532	0.0012	864	2
H'GANJC-3	COAL	0.89	17.88	1599.03	8.9	7.17	94	4482	0.0012	864	2
NCR-1DADRI	COAL	0.64	15.08	938.67	6.4	2.69	190	2687	0.0012	864	2
NCR-2	COAL	0.64	15.08	938.67	6.4	2.69	190	2687	0.0012	864	2
NCR-3	COAL	0.64	15.08	938.67	6.4	2.69	190	2687	0.0012	864	2
NCR-4	COAL	0.64	15.08	938.67	6.4	2.69	190	2687	0.0012	864	2
OBRA-1	COAL	2003	15.87	1540	10	7.15	36	4469	0.0012	864	2
OBRA-2	COAL	2003	15.87	1540	10	7.15	36	4469	0.0012	864	2
OBRA-3	COAL	2003	15.87	1540	10	7.15	36	4469	0.0012	864	2
OBRA-4	COAL	2003	15.87	1540	10	7.15	36	4469	0.0012	864	2
OBRA-5	COAL	2003	15.87	1540	10	7.15	36	4469	0.0012	864	2
OBRA-6	COAL	0.8	15.87	1232	8	5.72	84	3575	0.0012	864	2
OBRA-7	COAL	0.8	15.87	1232	8	5.72	84	3575	0.0012	864	2
OBRA-8	COAL	0.8	15.87	1232	8	5.72	84	3575	0.0012	864	2
OBRA-9	COAL	0.7	15.87	1078	7	3.09	181	3094	0.0012	864	2
OBRA-10	COAL	0.7	15.87	1078	7	3.09	181	3094	0.0012	864	2
OBRA-11	COAL	0.7	15.87	1078	7	3.09	181	3094	0.0012	864	2
OBRA-12	COAL	0.7	15.87	1078	7	3.09	181	3094	0.0012	864	2
OBRA-13	COAL	0.7	15.87	1078	7	3.09	181	3094	0.0012	864	2
PANKI-3	COAL	0.7	17.68	1232	7	5.58	94	3485	0.0012	864	2
PANKI-4	COAL	0.7	17.68	1232	7	5.58	94	3485	0.0012	864	2
PANKI-1	COAL	2003	17.68	1760	10	7.97	29	4979	0.0012	864	2
PANKI-2	COAL	2003	17.68	1760	10	7.97	29	4979	0.0012	864	2
PARICHHA-1	COAL	0.89	12.77	1207.43	8.9	3.2	98	3200	0.0012	864	2
PARICHHA-2	COAL	0.89	12.77	1207.43	8.9	3.2	98	3200	0.0012	864	2
RIHANDSTPS-1	COAL	0.6	14.61	858	6	2.4	460	2401	0.0012	864	2
RIHANDSTPS-2	COAL	0.6	14.61	858	6	2.4	460	2401	0.0012	864	2
SINGRAULI-1	COAL	0.7	15.24	1052.33	7	2.97	181	2971	0.0012	864	2
SINGRAULI-2	COAL	0.7	15.24	1052.33	7	2.97	181	2971	0.0012	864	2
SINGRAULI-3	COAL	0.7	15.24	1052.33	7	2.97	181	2971	0.0012	864	2
SINGRAULI-4	COAL	0.7	15.24	1052.33	7	2.97	181	2971	0.0012	864	2
SINGRAULI-5	COAL	0.7	15.24	1052.33	7	2.97	181	2971	0.0012	864	2
SINGRAULI-6	COAL	0.55	15.24	826.83	5.5	2.3	460	2296	0.0012	864	2
SINGRAULI-7	COAL	0.55	15.24	826.83	5.5	2.3	460	2296	0.0012	864	2
TANDA-1	COAL	1.04	11.94	1334.67	10.4	3.5	98	3495	0.0012	864	2
TANDA-2	COAL	1.04	11.94	1334.67	10.4	3.5	98	3495	0.0012	864	2
TANDA-3	COAL	1.04	11.94	1334.67	10.4	3.5	98	3495	0.0012	864	2
TANDA-4	COAL	1.04	11.94	1334.67	10.4	3.5	98	3495	0.0012	864	2
UNCHAHAR-3	COAL	0.7	15.08	1026.67	7	2.94	190	2939	0.0012	864	2
UNCHAHAR-1	COAL	0.7	15.08	1026.67	7	2.94	190	2939	0.0012	864	2
UNCHAHAR-2	COAL	0.7	15.08	1026.67	7	2.94	190	2939	0.0012	864	2
AURIYAGAS-1	GAS	0.221	41.74	504.43	0.37	1.59	109	1982	0.0008	1296	1.67
AURIYAGAS-2	GAS	0.221	41.74	504.43	0.37	1.59	109	1982	0.0008	1296	1.67
AURIYAGAS-3	GAS	0.221	41.74	504.43	0.37	1.59	109	1982	0.0008	1296	1.67
AURIYAGAS-4	GAS	0.221	41.74	504.43	0.37	1.59	109	1982	0.0008	1296	1.67
AURIYAGAS-5	GAS	0.221	41.74	504.43	0.37	1.59	99	1982	0.0008	1296	1 67
AURIYAGAS-6	GAS	0.221	41.74	504.43	0.37	1.59	99	1982	0.0008	1296	1.67
DADRICCGT-A-1	GAS	0.221	41.74	504.43	0.37	1.59	127	1982	0.0008	1296	1.67
DADRICCGT-A-2	GAS	0.221	41.74	504.43	0.37	1.59	127	1982	0.0008	1296	1.67
DADRICCGT-A-3	GAS	0.221	41.74	504.43	0.37	1.59	127	1982	0.0008	1296	1.67
DADRICCGT-A-4	GAS	0.221	41.74	504.43	0.37	1.59	127	1982	0.0008	1296	1.67
DADRICCGT-B-1WH	GAS	0.221	41.74	504.43	0.37	1.59	142	1982	0.0008	1296	1.67
DADRICCGT-B-2WH	GAS	0.221	41.74	504.43	0.37	1.59	142	1982	0.0008	1296	1.67
NAPP-1	NUCL	0.027	406350	0	0	0	198	2844	0.0015	864	2
NAPP-2	NUCL	0.027	406350	0	0	0	198	2844	0.0015	864	2
PANIPAT-6	COAL	0.812	13.49	1190.93	8.12	2.76	190	2762	0.0012	864	2
FARIDABADCCGT-A	GAS	0.237	41.74	540.95	0.39	1.65	139	2062	0.0008	1296	1.67
FARIDABADCCGT-B	GAS	0.237	41.74	540.95	0.39	1.65	140	2062	0.0008	1296	1.67

SURATGARHTPS-I2	COAL	0.812	13.49	1131.39	8.12	2.76	226	2762	0.0012	864	2
BARSINGSARLIG-1	COAL	0.986	11.11	1265.37	19.72	2.76	226	2762	0.0012	864	2
BARSINGSARLIG-2	COAL	0.986	11.11	1265.37	19.72	2.76	226	2762	0.0012	864	2
ANTA-IICCGT-1	GAS	0.237	41.74	540.95	0.39	1.65	107	2062	0.0008	1296	1.67
ANTA-IICCGT-2	GAS	0.237	41.74	540.95	0.39	1.65	107	2062	0.0008	1296	1.67
ANTA-IICCGT-3	GAS	0.237	41.74	540.95	0.39	1.65	107	2062	0.0008	1296	1.67
ANTA-IICCGT-4	GAS	0.237	41.74	540.95	0.39	1.65	104	2062	0.0008	1296	1.67
ANTA-IICCGT-5	GAS	0.237	41.74	540.95	0.39	1.65	104	2062	0.0008	1296	1.67
RAPP-3	NUCL	0.027	406350	0	0	0	198	2777	0.0015	864	2
RAPP-4	NUCL	0.027	406350	0	0	0	198	2777	0.0015	864	2
ANPARA'C'-1	COAL	0.719	15	1054.53	7.19	2.72	460	2717	0.0012	864	2
ANPARA'C'-2	COAL	0.719	15	1054.53	7.19	2.72	460	2717	0.0012	864	2
RIHAND-II-1	COAL	0.679	15.87	1045.66	6.79	2.72	460	2717	0.0012	864	2
RIHAND-II-2	COAL	0.679	15.87	1045.66	6.79	2.72	460	2717	0.0012	864	2
ROSAI/1	COAL	0.812	13.49	1131.39	8.12	2.76	257	2762	0.0012	864	2
ROSAI/2	COAL	0.812	13.49	1131.39	8.12	2.76	257	2762	0.0012	864	2
UNCHAHAR-4	COAL	0.691	15.87	1064.14	6.91	2.76	190	2762	0.0012	864	2
AURIYA-IICCGT-1	GAS	0.237	41.74	540.95	0.39	1.65	107	2062	0.0008	1296	1.67
AURIYA-IICCGT-2	GAS	0.237	41.74	540.95	0.39	1.65	107	2062	0.0008	1296	1.67
AURIYA-IICCGT-3	GAS	0.237	41.74	540.95	0.39	1.65	104	2062	0.0008	1296	1 67
AURIYA-IICCGT-4	GAS	0.237	41.74	540.95	0.39	1.65	104	2062	0.0008	1296	1.67
AURIYA-IICCGT-5	GAS	0.237	41.74	540.95	0.39	1.65	104	2062	0.0008	1296	1.67
GLOBALBOARDCGT	GAS	0.237	41.74	540.95	0.39	1.65	126	2062	0.0008	1296	1.67
MAGNUMCCGT	GAS	0.237	41.74	540.95	0.39	1.65	24	2062	0.0008	1296	1.67
PHOENIXCCGT	GAS	0.237	41.74	540.95	0.39	1.65	170	2062	0.0008	1296	1.67
AURIYA-IICCGT-6	GAS	0.237	41.74	540.95	0.39	1.65	104	2062	0.0008	1296	1.67
ANTA-IICCGT-6	GAS	0.237	41.74	540.95	0.39	1.65	104	2062	0.0008	1296	1.67
DHOLPURCCGT	GAS	0.237	41.74	540.95	0.39	1.65	233	2062	0.0008	1296	1.67
SURATGARH-II	COAL	0.812	13.49	1131.39	8.12	2.76	226	2762	0.0012	864	2
SURATGARH-II	COAL	0.812	13.49	1131.39	8.12	2.76	226	2762	0.0012	864	2
MATHANIACCGT	GAS	0.237	41.74	540.95	0.39	1.65	34	2062	0.0008	1296	1 67
MATHANIACCGT	GAS	0.237	41.74	540.95	0.39	1.65	34	2062	0.0008	1296	1.67
MATHANIACCGT	GAS	0.237	41.74	540.95	0.39	1.65	68	2062	0.0008	1296	1.67

B-2: Existing hydro power plants

Name	Capacity (MW)	EA year	Availibility	Opearting cost (000'$/ MWh)	Fixed O&M cost (000'$/ MWmonth)	Energy - Season1 (MWh)	Energy- Season2 (MWh)
W.Y.CANAL-1	8	2003	0.87	0	1.39	11000	31000
W.Y.CANAL-2	8	2003	0.87	0	1.39	11000	31000
W.Y.CANAL-3	8	2003	0.87	0	1.39	11000	31000
W.Y.CANAL-4	8	2003	0.87	0	1.39	11000	31000
W.Y.CANAL-5	8	2003	0.87	0	1.39	11000	31000
W.Y.CANAL-6	8	2003	0.87	0	1.39	11000	31000
ANDHRAU-1-3	17	2003	0.87	0	1.39	24000	33000
HPSMALL	9	2003	0.87	0	1.39	36000	57000
BAIRASIUL-1	60	2003	0.87	0	1.39	57000	190000
BAIRASIUL-2	60	2003	0.87	0	1.39	57000	191000
BAIRASIUL-3	60	2003	0.87	0	1.39	57000	190000
BANER	12	2003	0.87	0	1.39	14000	23000
THIROT	4.5	2003	0.87	0	1.39	19000	29000
GAJ	10.5	2003	0.87	0	1.39	5000	9000
BASSI-1	15	2003	0.87	0	1.39	28000	49000
BASSI-2	15	2003	0.87	0	1.39	28000	49000
BASSI-3	15	2003	0.87	0	1.39	28000	49000
BASSI-4	15	2003	0.87	0	1.39	28000	49000
BINWA	6	2003	0.87	0	1.39	14000	27000
CHAMERA-I-1	180	2003	0.87	0	1.39	314000	400000
CHAMERA-I-2	180	2003	0.87	0	1.39	314000	400000
CHAMERA-I-3	180	2003	0.87	0	1.39	315000	400000
GIRIBATA-1	30	2003	0.87	0	1.39	48000	77000
GIRIBATA-2	30	2003	0.87	0	1.39	48000	77000
SANJAYBHABA-1	40	2003	0.87	0	1.39	78000	113000
SANJAYBHABA-2	40	2003	0.87	0	1.39	78000	113000
SANJAYBHABA-3	40	2003	0.87	0	1.39	79000	113000
CHENANI	23	2003	0.87	0	1.39	30000	60000

GANDERBAL	15	2003	0.87	0	1.39	13000	26000
J&K-SMALL	6	2003	0.87	0	1.39	5000	9000
KARGIL	4	2003	0.87	0	1.39	5000	9000
LOWERJHELUM	105	2003	0.87	0	1.39	171000	362000
MOHORA	9	2003	0.87	0	1.39	26000	53000
SALAL-I-1	115	2003	0.87	0	1.39	339000	508000
SALAL-I-2	115	2003	0.87	0	1.39	339000	508000
SALAL-I-3	115	2003	0.87	0	1.39	339000	509000
SALAL-II-1	115	2003	0.87	0	1.39	142000	212000
SALAL-II-2	115	2003	0.87	0	1.39	142000	212000
SALAL-II-3	115	2003	0.87	0	1.39	142000	213000
UPPERSINDH-I	22.6	2003	0.87	0	1.39	33000	68000
URI-1	120	2003	0.87	0	1.39	175000	407000
URI-2	120	2003	0.87	0	1.39	175000	407000
URI-3	120	2003	0.87	0	1.39	5000	407000
URI-4	120	2003	0.87	0	1.39	175000	407000
ANANDPURSAHIB1	34	2003	0.87	0	1.39	61000	166000
ANANDPURSAHIB2	34	2003	0.87	0	1.39	61000	166000
ANANDPURSAHIB3	34	2003	0.87	0	1.39	61000	166000
ANANDPURSAHIB4	34	2003	0.87	0	1.39	62000	166000
BEASDEHAR-1	165	2003	0.87	0	1.39	197000	367000
BEASDEHAR-2	165	2003	0.87	0	1.39	197000	367000
BEASDEHAR-3	165	2003	0.87	0	1.39	197000	367000
BEASDEHAR-4	165	2003	0.87	0	1.39	197000	367000
BEASDEHAR-5	165	2003	0.87	0	1.39	197000	367000
BEASDEHAR-6	165	2003	0.87	0	1.39	198000	367000
BEASPONG-1	60	2003	0.87	0	1.39	84000	226000
BEASPONG-2	60	2003	0.87	0	1.39	84000	226000
BEASPONG-3	60	2003	0.87	0	1.39	84000	226000
BEASPONG-4	60	2003	0.87	0	1.39	84000	226000
BEASPONG-5	60	2003	0.87	0	1.39	84000	226000
BEASPONG-6	60	2003	0.87	0	1.39	84000	226000
BHAKRA(LB)-1	108	2003	0.87	0	1.39	156000	346000
BHAKRA(LB)-2	108	2003	0.87	0	1.39	156000	346000
BHAKRA(LB)-3	108	2003	0.87	0	1.39	156000	346000
BHAKRA(LB)-4	108	2003	0.87	0	1.39	156000	347000
BHAKRA(LB)-5	108	2003	0.87	0	1.39	156000	347000
BHAKRA(RB)-1	142	2003	0.87	0	1.39	205000	455000
BHAKRA(RB)-2	142	2003	0.87	0	1.39	205000	455000
BHAKRA(RB)-3	142	2003	0.87	0	1.39	205000	455000
BHAKRA(RB)-4	142	2003	0.87	0	1.39	205000	455000
BHAKRA(RB)-5	142	2003	0.87	0	1.39	205000	455000
GANGUWAL-1	29	2003	0.87	0	1.39	43000	150000
GANGUWAL-2	25	2003	0.87	0	1.39	43000	150000
GANGUWAL-3	24	2003	0.87	0	1.39	43000	150000
KOTLA-1	29	2003	0.87	0	1.39	43000	150000
KOTLA-2	25	2003	0.87	0	1.39	43000	150000
KOTLA-3	24	2003	0.87	0	1.39	43000	150000
MUKERIAN-1	15	2003	0.87	0	1.39	27000	71000
MUKERIAN-2	15	2003	0.87	0	1.39	27000	71000
MUKERIAN-3	15	2003	0.87	0	1.39	27000	71000
MUKERIAN-4	15	2003	0.87	0	1.39	27000	71000
MUKERIAN-5	15	2003	0.87	0	1.39	27000	71000
MUKERIAN-6	15	2003	0.87	0	1.39	27000	71000
MUKERIAN-7	20	2003	0.87	0	1.39	36000	93000
MUKERIAN-8	19	2003	0.87	0	1.39	36000	93000
MUKERIAN-9	20	2003	0.87	0	1.39	36000	93000
MUKERIAN-10	19	2003	0.87	0	1.39	36000	93000
MUKERIAN-11	20	2003	0.87	0	1.39	36000	93000
MUKERIAN-12	19	2003	0.87	0	1.39	36000	93000
SHANAN-1	15	2003	0.87	0	1.39	35000	60000
SHANAN-2	15	2003	0.87	0	1.39	35000	60000
SHANAN-3	15	2003	0.87	0	1.39	36000	60000
SHANAN-4	15	2003	0.87	0	1.39	36000	60000
SHANAN-5	50	2003	0.87	0	1.39	70000	120000
UBDC-1	15	2003	0.87	0	1.39	22000	21000
UBDC-2	15	2003	0.87	0	1.39	22000	21000
UBDC-3	15	2003	0.87	0	1.39	22000	21000
UBDC-4	15	2003	0.87	0	1.39	22000	21000

UBDC-5	15	2003	0.87	0	1.39	22000	21000
UBDC-6	15	2003	0.87	0	1.39	22000	22000
ANOOPGARH	9	2003	0.87	0	1.39	0	4000
JAWAHARSAGAR	99	2003	0.87	0	1.39	82000	348000
MAHI-1	25	2003	0.87	0	1.39	13000	55000
MAHI-2	25	2003	0.87	0	1.39	13000	57000
MAHI-3	45	2003	0.87	0	1.39	22000	95000
MAHI-4	45	2003	0.87	0	1.39	22000	95000
R.P.SAGAR	172	2003	0.87	0	1.39	91000	513000
RAJ-SMALL	14	2003	0.87	0	1.39	0	9000
CHIBRO-1	60	2003	0.87	0	1.39	87000	147000
CHIBRO-2	60	2003	0.87	0	1.39	87000	147000
CHIBRO-3	60	2003	0.87	0	1.39	87000	147000
CHIBRO-4	60	2003	0.87	0	1.39	87000	147000
DHAKRANI-1	11	2003	0.87	0	1.39	16000	37000
DHAKRANI-2	11	2003	0.87	0	1.39	16000	37000
DHAKRANI-3	12	2003	0.87	0	1.39	16000	37000
DHALIPUR-1	17	2003	0.87	0	1.39	27000	63000
DHALIPUR-2	17	2003	0.87	0	1.39	27000	63000
DHALIPUR-3	17	2003	0.87	0	1.39	27000	64000
KHARA-1	24	2003	0.87	0	1.39	41000	91000
KHARA-2	24	2003	0.87	0	1.39	41000	91000
KHARA-3	24	2003	0.87	0	1.39	41000	91000
KHATIMAGANGA	41.4	2003	0.87	0	1.39	59000	139000
KHODRI-1	30	2003	0.87	0	1.39	38000	71000
KHODRI-2	30	2003	0.87	0	1.39	38000	71000
KHODRI-3	30	2003	0.87	0	1.39	39000	71000
KHODRI-4	30	2003	0.87	0	1.39	39000	71000
KULHALST-IV-1	10	2003	0.87	0	1.39	16000	37000
KULHALST-IV-2	10	2003	0.87	0	1.39	16000	37000
KULHALST-IV-3	10	2003	0.87	0	1.39	16000	37000
CHILLA-1	36	2003	0.87	0	1.39	52000	120000
CHILLA-2	36	2003	0.87	0	1.39	52000	120000
CHILLA-3	36	2003	0.87	0	1.39	52000	121000
CHILLA-4	36	2003	0.87	0	1.39	52000	121000
MANERIBHALI-I1	30	2003	0.87	0	1.39	19000	99000
MANERIBHALI-I2	30	2003	0.87	0	1.39	19000	99000
MANERIBHALI-I3	30	2003	0.87	0	1.39	19000	99000
MATATILA-1	10	2003	0.87	0	1.39	16000	27000
MATATILA-2	10	2003	0.87	0	1.39	16000	27000
MATATILA-3	10	2003	0.87	0	1.39	17000	27000
OBRA-1-H	33	2003	0.87	0	1.39	26000	100000
OBRA-2-H	33	2003	0.87	0	1.39	26000	100000
OBRA-3-H	33	2003	0.87	0	1.39	26000	100000
RAMGANGA-1	66	2003	0.87	0	1.39	0	98000
RAMGANGA-2	66	2003	0.87	0	1.39	0	98000
RAMGANGA-3	66	2003	0.87	0	1.39	0	99000
RIHAND-1	50	2003	0.87	0	1.39	34000	138000
RIHAND-2	50	2003	0.87	0	1.39	34000	138000
RIHAND-3	50	2003	0.87	0	1.39	34000	137000
RIHAND-4	50	2003	0.87	0	1.39	34000	137000
RIHAND-5	50	2003	0.87	0	1.39	34000	137000
RIHAND-6	50	2003	0.87	0	1.39	34000	137000
TANAKPUR-1	30	2003	0.87	0	1.39	41000	69000
TANAKPUR-2	30	2003	0.87	0	1.39	41000	69000
TANAKPUR-3	30	2003	0.87	0	1.39	41000	69000
GANGACANAL	45.2	2003	0.87	0	1.39	32000	118000
SOBLA	6	2003	0.87	0	1.39	0	53000
TANAKPUR-4	30	2003	0.87	0	1.39	41000	70000
DADUPUR	6	2003	0.87	0	1.39	5000	13000
W.Y.C.-II	16	2003	0.87	0	1.39	16000	48000
BASPAII-1	100	2003	0.87	0	1.39	161000	241000
BASPAII-2	100	2003	0.87	0	1.39	161000	241000
BASPAII-3	100	2003	0.87	0	1.39	161000	241000
CHAMERA-II-1	100	2004	0.87	0	1.39	170000	254000
CHAMERA-II-2	100	2004	0.87	0	1.39	169000	254000
CHAMERA-II-3	100	2004	0.87	0	1.39	169000	254000
KOLDAM-1	200	2006	0.87	0	1.39	307000	461000
KOLDAM-2	200	2006	0.87	0	1.39	307000	461000

KOLDAM-3	200	2007	0.87	0	1.39	307000	461000
KOLDAM-4	200	2007	0.87	0	1.39	307000	461000
LARJI1-3	126	2004	0.87	0	1.39	131000	196000
GHANVI	22.5	2003	0.87	0	1.39	18000	26000
NATHPAJHAKRI-1&2	500	2003	0.87	0	1.39	663000	996000
NATHPAJHAKRI-3	250	2003	0.87	0	1.39	332000	497000
NATHPAJHAKRI-4	250	2003	0.87	0	1.39	332000	497000
NATHPAJHAKRI-5	250	2003	0.87	0	1.39	332000	497000
NATHPAJHAKRI-6	250	2003	0.87	0	1.39	332000	497000
PARVATI-II-1	200	2006	0.87	0	1.39	318000	476000
PARVATI-II-2	200	2006	0.87	0	1.39	318000	476000
PARVATI-II-3	200	2007	0.87	0	1.39	318000	476000
PARVATI-II-4	200	2007	0.87	0	1.39	318000	476000
CHENANI-II	7.5	2003	0.87	0	1.39	6000	12000
DULHASTI-1	130	2003	0.87	0	1.39	257000	386000
DULHASTI-2	130	2003	0.87	0	1.39	257000	386000
DULHASTI-3	130	2003	0.87	0	1.39	257000	386000
PAHALGAON	3	2003	0.87	0	1.39	2000	3000
PARNAIHEP1	12.5	2003	0.87	0	1.39	26000	54000
SEWA-III	9	2003	0.87	0	1.39	16000	31000
UPPERSINDH-II	70	2003	0.87	0	1.39	53000	109000
UPPERSINDH-III	35	2003	0.87	0	1.39	27000	54000
SHAHPURKHANDI	40	2004	0.87	0	1.39	51000	115000
SYLCANAL	50	2003	0.87	0	1.39	127000	190000
THEINDAM-1	150	2003	0.87	0	1.39	105000	235000
THEINDAM-2	150	2003	0.87	0	1.39	106000	235000
THEINDAM-3	150	2003	0.87	0	1.39	106000	235000
THEINDAM-4	150	2003	0.87	0	1.39	106000	235000
JAKHAM	5	2003	0.87	0	1.39	5000	22000
KATAPATHARHE	19	2006	0.87	0	1.39	19000	35000
DHAULIGANGA-I-1	140	2004	0.87	0	1.39	198000	369000
DHAULIGANGA-I-2	140	2004	0.87	0	1.39	198000	369000
KOTESHWAR-1	100	2005	0.87	0	1.39	108000	200000
KOTESHWAR-2	100	2005	0.87	0	1.39	108000	200000
KOTESHWAR-3	100	2006	0.87	0	1.39	108000	200000
KOTESHWAR-4	100	2006	0.87	0	1.39	108000	200000
LAKHWAR[VYASI]1	100	2005	0.87	0	1.39	55000	103000
LAKHWAR[VYASI]2	100	2005	0.87	0	1.39	55000	103000
MANERIBH-II-1	76	2004	0.87	0	1.39	82000	152000
MANERIBH-II-2	76	2004	0.87	0	1.39	82000	152000
MANERIBH-II-3	76	2004	0.87	0	1.39	82000	152000
MANERIBH-II-4	76	2004	0.87	0	1.39	82000	152000
RAJGHAT50%	22	2003	0.87	0	1.39	15000	29000
TEHRISTI-1	250	2003	0.87	0	1.39	251000	466000
TEHRISTI-2	250	2003	0.87	0	1.39	251000	466000
TEHRISTI-3	250	2003	0.87	0	1.39	251000	466000
TEHRISTI-4	250	2003	0.87	0	1.39	251000	466000
VISHNUPRAYAG-1	100	2003	0.87	0	1.39	118000	220000
VISHNUPRAYAG-2	100	2003	0.87	0	1.39	118000	220000
VISHNUPRAYAG-3	100	2003	0.87	0	1.39	118000	220000
VISHNUPRAYAG-4	100	2003	0.87	0	1.39	118000	220000
VYASI[LAKWAR]	120	2004	0.87	0	1.39	132000	244000
LAKHWARVYASI3	100	2005	0.87	0	1.39	55000	103000
PARNAIHEP2	12.5	2004	0.87	0	1.39	26000	54000
PARNAIHEP3	12.5	2004	0.87	0	1.39	26000	54000
TEHRIII-1	250	2005	0.87	0	1.39	251000	465000
TEHRIII-2	250	2005	0.87	0	1.39	251000.	465000
TEHRIII-3	250	2006	0.87	0	1.39	251000	465000
TEHRI-II-4	250	2006	0.87	0	1.39	251000	465000
SHAHPURKHANDI	40	2004	0.87	0	1.39	51000	114000
SHAHPURKHANDI	40	2004	0.87	0	1.39	51000	114000
SHAHPURKHANDI	40	2005	0.87	0	1.39	51000	114000
SHAHPURKHANDI	8	2004	0.87	0	1.39	10000	23000
MALANAHEP	86	2004	0.87	0	1.39	123000	185000

Appendix C

Candidate Plants

C-1: Candidate Thermal Plants

Name	*Coal 4 -500*	*Coal 6 -500*	*CCGT -500*	*Nuclear -500*
Fuel type used	Coal 4	Coal 6	Gas	Nuclear
Fuel consumptionrate unit	000'kg/MWh	000'kg/MWh	000'm3/MWh	000'gm/MWh
Fuel consumption	0.7	0.7	0.2	0.027
Calorific value kBtu/kg)	13.5	13.5	41.74	406350
CO2 emission factor (kg/MWh)	1026	1026	550	0
SO2 emission factor (kg/MWh)	6	6	0.4	0
NOx emission factor(kg/MWh)	2.5	2.5	1.64	0
Installed capacity(MW)	500	500	250	500
Earliest availableyear	2003	2003	2003	2006
Annual allowablemaximum unit	60	30	80	6
Availability	0.71	0.71	0.8	0.58
Unit depreciablecapital cost (k$)	450000	450000	175000	600000
Unit non-depreciablecapital cost (k$)	50000	50000	19500	66000
Heat rate at full load(Mcal/MWh)	2500	2500	2062	2777
Operating cost(k$/MWh)	0.0012	0.0012	0.0008	0.0015
Annual maintenancehour	864	864	1296	896
Fixed O&M cost(k$/MWmonth	2	2	1.67	2.7

C-2: Candidate Hydro Plants

Name	*Capacity*	*Year*	*Unit*	*Cost*	*En. Sea.1*	*En. Sea.2*
Hibra	120	2007	2	143555	187200	280800
Palamaneri	100	2007	4	42265	137900	256100
Budhil	35	2008	2	37729	57200	85800
L. Nagpala	250	2008	2	82109	339325	630175
Kuther	130	2009	2	119444	188200	282300
Uhl st. III	50	2010	2	49019	80400	120600
Maner Bali	76	2010	4	84512	115850	215150
T. Vishnugadh	120	2010	3	56465	185033	343633
Parbati III	167	2010	3	106071	266266	399400
Dhauliganga II	70	2010	3	90683	111416	206916
Kishanganga	110	2011	3	100529	102500	239166
Kotlibhel	250	2012	4	72508	473462	879287
Uri II	70	2012	4	137877	108450	253050
Bursar	250	2014	4	144632	121950	284550
Shahpur Kandi	168	2014	1	299177	333440	708560
Sewa st II	60	2014	2	38258	47250	110250
Pakhal dul	250	2015	4	59941	44250	103250
Kishau	120	2015	5	153555	92890	172510
Parbati I	250	2015	3	278000	391200	586800

C-3: Existing Thermal IPPs

NAME	*Fuel type*	*Fuel con.*	*Cal. Value (kBtu/ kg)*	*CO2 emis. (kg/ MWh)*	*SO2 emis. (kg/ MWh)*	*NOx emis. (kg/ MWh)*	*Capacity (MW)*	*Heat rate (kcal/ kwh)*	*Oper. cost (000'$/ MWh)*	*Annual maint. (Hours)*	*Fixed O&M (000'$/ MWmonth)*
BARSINGSARLIG-1	COAL	0.986	11.11	1265.37	19.72	2.76	226	2762	0.0012	864	2
BARSINGSARLIG-2	COAL	0.986	11.11	1265.37	19.72	2.76	226	2762	0.0012	864	2
ROSAI/1	COAL	0.812	13.49	1131.39	8.12	2.76	257	2762	0.0012	864	2
ROSAI/2	COAL	0.812	13.49	1131.39	8.12	2.76	257	2762	0.0012	864	2
DHOLPURCCGT	GAS	0.237	41.74	540.95	0.39	1.65	233	2062	0.0008	1296	1.67
GLOBALBOARDCGT	GAS	0.237	41.74	540.95	0.39	1.65	126	2062	0.0008	1296	1.67
MAGNUMCCGT	GAS	0.237	41.74	540.95	0.39	1.65	24	2062	0.0008	1296	1.67
PHOENIXCCGT	GAS	0.237	41.74	540.95	0.39	1.65	170	2062	0.0008	1296	1.67

C-4: Existing Hydro IPPs

Name	*Capacity (MW)*	*EA year*	*Availibility*	*Opearting Cost (000'$/ MWh)*	*Fixed O&M cost (000'$/ MWmonth)*	*Energy - Season1 (MWh)*	*Energy- Season2 (MWh)*
BASPAII-1	100	2003	0.87	0	1.39	161000	241000
BASPAII-2	100	2003	0.87	0	1.39	161000	241000
BASPAII-3	100	2003	0.87	0	1.39	161000	241000
VISHNUPRAYAG-1	100	2003	0.87	0	1.39	118000	220000
VISHNUPRAYAG-2	100	2003	0.87	0	1.39	118000	220000
VISHNUPRAYAG-3	100	2003	0.87	0	1.39	118000	220000
VISHNUPRAYAG-4	100	2003	0.87	0	1.39	118000	220000
MALANAHEP	86	2004	0.87	0	1.39	123000	185000

C-5: Candidate Thermal IPPs

Name	*Jawaharpur TPP*
Fuel type used	Coal 6
Fuel consumption rate unit	000'kg/MWh
Fuel consumption	0.7
Calorific value (kBtu/kg)	17.8
CO2 emission factor (kg/MWh)	1026
SO2 emission factor (kg/MWh)	6
NOx emission factor (kg/MWh)	2.5
Installed capacity (MW)	400
Earliest available year	2007
Annual allowable maximum unit	2
Availability	0.71
Unit depreciable capital cost (k$)	353391
Unit non-depreciable capital cost (k$)	39265
Heat rate at full load (Mcal/MWh)	2200
Operating cost (k$/MWh)	0.0012
Annual maintenance hour	864
Fixed O&M cost (k$/MWmonth)	2

Chapter 2 C-6: Candidate Hydro IPPs

Name	Capacity	Year	Unit	Cost	Season1	Season2
Allan duhangan	96	2009	2	76955	136400	204600
K.Wangtoo	250	2007	4	286026	440200	660300
D. Sunda	35	2008	2	40250	56800	85200
Srinagar HEP	82.5	2007	4	95980	123000	185000

Appendix D

Candidate Plants

D-1: Candidate Thermal Plants

Name	Coal 4 - 500	Coal 6 - 500	CCGT – 500	Nuclear - 500	PFBC - 450	IGCC - 400	BIGCC-132
Fuel type used	Coal 4	Coal 6	Gas	Nuclear	Coal 6	Coal 6	wood
Fuel consumption rate unit	000'kg/ MWh	000'kg/ MWh	000'm3/ MWh	000'gm/ MWh	000'kg/ MWh	000'kg/ MWh	000'kg/ MWh
Fuel Consumption	0.7	0.7	0.2	0.027	0.51	0.51	0.51
Calorific value (kBtu/kg)	13.5	13.5	41.74	406350	15.56	15.56	19.21
CO2 emission factor (kg/MWh)	1026	1026	550	0	907	551	71.64
SO2 emission factor (kg/MWh)	6	6	0.4	0	0.255	0.235	0.918
NOx emission factor (kg/MWh)	2.5	2.5	1.64	0	0.6	0.6	0.6
Installed capacity (MW)	500	500	250	500	450	400	132
Earliest available year	2004	2005	2003	2007	2005	2005	2005
Annual allowable Maximum unit	85	45	80	6	10	10	10
Availability	0.71	0.71	0.8	0.58	0.85	0.85	0.85
Unit depreciable Capital cost (k$)	450000	450000	175000	600000	510000	500000	162875
Unit non-depreciable Capital cost (k$)	50000	50000	19500	66000	52500	50000	18100
Heat rate at full load (Mcal/MWh)	2500	2500	2062	2777	2013	1850	2469
Operating cost (k$/MWh)	0.0012	0.0012	0.0008	0.0015	0.0012	0.0013	0.0174
Annual maintenance hour	864	864	1296	896	864	864	864
Fixed O&M cost (k$/MWmonth	2	2	1.67	2.7	2.2	2.32	5.4

D-2: Candidate Hydro Plants

Name	*Capacity*	*Year*	*Unit*	*Cost*	*Season1*	*Season2*
Hibra	120	2007	2	143555	187200	280800
K.Wangtoo	250	2007	4	286026	440200	660300
Palamaneri	100	2007	4	42265	137900	256100
Budhil	35	2008	2	37729	57200	85800
L. Nagpala	250	2008	2	82109	339325	630175
Kuther	130	2009	2	119444	188200	282300
Allan duhangan	96	2009	2	76955	136400	204600
Uhl st. III	50	2010	2	49019	80400	120600
Maner Bali	76	2010	4	84512	115850	215150

T. Vishnugadh	120	2010	3	56465	185033	343633
Parbati III	167	2010	3	106071	266266	399400
Dhauliganga II	70	2010	3	90683	111416	206916
Kishanganga	110	2011	3	100529	102500	239166
Kotlibhel	250	2012	4	72508	473462	879287
Uri II	70	2012	4	137877	108450	253050
Bursar	250	2014	4	144632	121950	284550
Shahpur Kandi	168	2014	1	299177	333440	708560
Sewa st II	60	2014	2	38258	47250	110250
Pakhal dul	250	2015	4	59941	44250	103250
Kishau	120	2015	5	153555	92890	172510
Parbati I	250	2015	3	278000	391200	586800

D-3: Existing DPG (Micro-hydro)

Name	Capacity (MW)	EA Year	Avail.	Opearting Cost (000'\$/ MWh)	Fixed O&M cost (000'\$/ MWmonth)	Generation pattern Season1	Generation pattern Season2
Karnah-I	1	2003	0.87	0	1.86	0.4166	0.3276
Karnah-II	1	2003	0.87	0	1.86	0.4166	0.3276
Stakna-I	2	2003	0.87	0	1.86	0.4166	0.3276
Stakna-II	2	2003	0.87	0	1.86	0.4166	0.3276
chennani-II-I	1	2003	0.87	0	1.86	0.4166	0.3276
chennani-II-II	1	2003	0.87	0	1.86	0.4166	0.3276
Sal st II-I	1	2003	0.87	0	1.86	0.5554	0.2808
Sal st II-II	1	2003	0.87	0	1.86	0.5554	0.2808
gumma-I	1.5	2003	0.87	0	1.86	0.5554	0.2808
gumma-II	1.5	2003	0.87	0	1.86	0.5554	0.2808
charanwala	1.2	2003	0.87	0	1.86	0.4166	0.3276
pugal 1	1.5	2003	0.87	0	1.86	0.4166	0.3276
RMC mangrol-I	2	2003	0.87	0	1.86	0.4166	0.3276
RMC mangrol-II	2	2003	0.87	0	1.86	0.4166	0.3276
RMC mangrol-III	2	2003	0.87	0	1.86	0.4166	0.3276
suratgarh-I	2	2003	0.87	0	1.86	0.4166	0.3276
suratgarh-II	2	2003	0.87	0	1.86	0.4166	0.3276
chitaura-I	1.5	2003	0.87	0	1.86	0.4860	0.3042
chitaura-II	1.5	2003	0.87	0	1.86	0.4860	0.3042
salwa-I	1.5	2003	0.87	0	1.86	0.4860	0.3042
salwa-II	1.5	2003	0.87	0	1.86	0.4860	0.3042
galogi-I	1	2003	0.87	0	1.86	0.4860	0.3042
galogi-II	1	2003	0.87	0	1.86	0.4860	0.3042
chirkilla	1	2003	0.87	0	1.86	0.4860	0.3042
urgam-I	1.5	2003	0.87	0	1.86	0.4860	0.3042
urgam-II	1.5	2003	0.87	0	1.86	0.4860	0.3042

nirgajni-I	2.5	2003	0.87	0	1.86	0.4860	0.3042
nirgajni-II	2.5	2003	0.87	0	1.86	0.4860	0.3042

D-4: Candidate DPG

Name	*Microhydro-2*	*Solar PV -2*	*Wind -2*
Fuel type used	Water	Solar	Wind
CO2 emission factor (kg/MWh)	0	0	0
SO2 emission factor (kg/MWh)	0	0	0
NOx emission factor (kg/MWh)	0	0	0
Installed capacity (MW)	2	2	2
Earliest available year	2003	2003	2003
Annual allowable Maximum unit	500	50	50
Availability	0.87	0.25	0.35
Unit depreciable Capital cost (k$)	2222.2	6000	1400
Unit non-depreciable Capital cost (k$)	0	0	0
Operating cost (k$/MWh)	0	0.0012	0.00075
Annual maintenance hour	0	168	240
Fixed O&M cost (k$/MWmonth	1.86	2.5	1.35

D-5: Daily energy generation pattern of micro-hydro plants

	1	2	3	4	5	6	7	8	9	10	11	12
Sea.1	0.486	0.486	0.486	0.486	0.486	0.486	0.486	0.486	0.486	0.486	0.486	0.486
Sea.2	0.486	0.486	0.486	0.486	0.486	0.486	0.486	0.486	0.486	0.486	0.486	0.486
	13	14	15	16	17	18	19	20	21	22	23	24
Sea.1	0.3042	0.3042	0.3042	0.3042	0.3042	0.3042	0.3042	0.3042	0.3042	0.3042	0.3042	0.3042
Sea.2	0.3042	0.3042	0.3042	0.3042	0.3042	0.3042	0.3042	0.3042	0.3042	0.3042	0.3042	0.3042

D-6: Daily energy generation pattern of wind plants

	1	2	3	4	5	6	7	8	9	10	11	12
Sea.1	0.3703	.3730	.3636	.3313	.3263	.2882	.2714	.2648	.2659	.3009	0.3636	0.4094
Sea.2	0.3045	0.3080	0.3263	0.3414	0.3116	0.2511	0.2769	0.5344	0.7560	0.7824	0.8231	0.8867
	13	14	15	16	17	18	19	20	21	22	23	24
Sea.1	0.5140	0.5344	0.5140	0.5006	0.4420	0.3275	0.2459	0.2358	0.2769	0.2986	0.3238	0.3325
Sea.2	0.9160	0.9086	0.8940	0.9536	1.0000	0.7757	0.5768	0.4196	0.3376	0.3009	0.2974	0.3116

D-7: Daily energy generation pattern of solar plants

	1	2	3	4	5	6	7	8	9	10	11	12
Sea.1	0.0000	0.0000	0.0000	0.0000	0.0000	0.0149	0.1293	0.3402	0.5544	0.7327	0.8539	0.9246
Sea.2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0088	0.0859	0.3001	0.5557	0.7695	0.9234	1.0000
	13	14	15	16	17	18	19	20	21	22	23	24
Sea.1	0.9271	0.8535	0.7258	0.5476	0.3326	0.1301	0.0169	0.0000	0.0000	0.0000	0.0000	0.0000
Sea.2	0.9977	0.9176	0.7521	0.5341	0.2798	0.0786	0.0110	0.0000	0.0000	0.0000	0.0000	0.0000

Appendix E

Technological substitution Effect and Electricity Price Effect of Carbon Tax on Total CO_2 Emission Reduction

This section shows the methodology to determine the technological substitution effect and electricity price effect of carbon tax on total CO_2 emission reduction. Reduction in CO_2 emission in both supply- and demand side effect can be calculated by

Mitigation of CO_2 due to fuel and technological substitution in power generation (ΔE_s)(i.e., substitution effect) can be expressed as:

$$\Delta E_s = E_0 - E_s . \tag{E.1}$$

where, E_0 = CO_2 emission corresponding to the least cost fuel mix without carbon tax for given power demand projections and candidate power plants, and

E_s = CO_2 emission corresponding to the least cost fuel mix with carbon tax, all other things remaining the same as in case E_0.

CO_2 mitigation associated with electricity demand response to an increase in electricity price due to carbon tax (ΔE_p) is expressed as:

$$\Delta E_p = E_s - E_p \tag{E.2}$$

where, E_p = CO_2 emission corresponding to the least cost generation mix associated with the reduced level of electricity demand due to an increase in electricity price resulting from carbon tax, all other things remaining the same as in the case of E_s

Total CO_2 mitigation effect of carbon tax (ΔE) is then:

$$\begin{aligned} \Delta E &= E_0 - E_p \\ &= (E_0 - E_s) + (E_s - E_p) \\ &= \Delta E_s + \Delta E_p \\ &= \text{Technological Substitution Effect} + \text{Electricity Price Effect} \end{aligned} \tag{E.3}$$

CO_2 emissions are calculated using information on optimal fuel requirements and relevant emission factors.

- **Price Elasticity of electricity demand**

To determine the reduction in electricity demand after the change in electricity price. The price elasticity of electricity demand is used since it defined as a percentage change in electricity demand with respect to a percentage in electricity price, i.e.

Price elasticity of electricity demand

= Percentage change in electricity demand / Percentage change in the electricity price